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SECTORAL TECHNOLOGY
STRATEGY SERIES

# No 12

# *The Canadian Electric-Power Sector*

SECTORAL TECHNOLOGY STRATEGY SERIES

# NO. 12 THE CANADIAN ELECTRIC-POWER SECTOR

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# Highlights

- Canada's electric-power utilities are big. Ontario Hydro and Hydro-Québec are among the largest industrial organizations in Canada, and both are among the top 10 Canadian performers of industrial R&D. Several other Canadian utilities have notable R&D programs. Canada has developed many electric-power technologies domestically, including hydroelectric generation, long-distance transmission, and the CANDU nuclear system.

- The regulated-monopoly nature of Canadian power utilities has led to a noteworthy exploitation of economies of scale in power generation through technology strategies that favour development of large, centralized systems based on hydro sites or the CANDU nuclear technology, developed by Atomic Energy of Canada Ltd. (AECL).

- In most countries, electric-utility R&D is integrated into the internal structures of public utilities, as is the case with most Canadian power corporations including the largest, Hydro-Québec, Ontario Hydro, and B.C. Hydro. However, the Canadian Electrical Association (CEA) helps to coordinate Canadian R&D, and electric-power research is also supported by the federal government's Panel on Energy R&D (PERD). Electric-utility R&D tends to be primarily concerned with improving the utility's operational performance. Relatively little effort is dedicated to commercializing the products of their research or to developing new electrical products or electrotechnologies.

- Canadian utilities are in the middle of the pack as R&D performers by international standards. Compared with most of the other 14 sectors reviewed by the Science Council of Canada for the Sectoral Technology Strategy Series, this sector has a high level of performance.

- Japanese utilities pay a tax on their electricity sales. The tax supports a fund reserved exclusively for national R&D projects. This may be a model for Canada. The utilities draw on the fund for the national R&D mandates they are assigned. The Japanese make the biggest relative R&D effort in the electric-power sector. The R&D intensity is two or three times that of other major industrial countries.

- Prices for electricity are lower in Canada than in almost any country in the world. Canadian electric utilities claim they have highly efficient generating systems and low-cost resources: water, uranium, coal, and gas. They can also point to excellent safety records, including that for CANDU nuclear equipment.

- There is, however, controversy over Canadian power costs. Some critics claim that the utilities are directly and indirectly subsidized by provincial taxpayers and that rates would be higher if ordinary business practices applied. The rate-structure issue is very important; in a higher-rate environment, many different generating technologies might become economically viable, including several claimed to be more benign environmentally. However, a higher-rate environment might discourage further development of electricity-intensive industries such as the smelting and refining of metals.

- The controversy over technology strategies and real costs occasionally spills over into the issue of privatization of electric utilities. The technology strategies of Canadian utilities would probably change if they were privatized. In a privatized environment, investment decisions would likely

favour smaller, more modular generating technologies, with much less emphasis on economies of scale, even if this meant higher electricity rates in the long run.

- There is no agreement on the desirability of privatizing utilities. Moreover, although privatization has received considerable attention recently, other issues and indicators may more usefully illuminate how the sector can best develop its technology-strategy options.

- One technology-strategy issue concerns the load factor on the electric grid. Load factor is an index of how continuous the demand for electric power is. High load factors indicate relatively constant demand. This demand is best met by large, centralized power sources called base-load generators. Low load factors indicate fluctuating demand. This type of demand offers opportunities for small-scale, decentralized, modular power generation. Although hydraulic-based systems are inherently more flexible than thermal-based ones, questions of water availability and storage make the load factor an important consideration even for them.

- Canadian electric utilities generally favour the development and construction of large, centralized base-load generators. Their R&D programs support this strategy. This strategy will be validated if high load factors become the norm. But if the load factor deteriorates, the alternative strategy of decentralized power production might be better and suggests a different R&D profile.

- One way to clarify the load-factor issue and related technological and management controversies is to implement new, differentiated public rate structures according to the load factor faced by the grid. Although electric utilities have historically tried to establish a single reference price for electricity, especially for household customers, the currently high real interest rate, as well as evolving technology, now makes alternative rate structures appropriate. Differentiated rate structures would resemble a deregulated environment. They might allow some of the flexibility and cost recovery of privatization without completely sacrificing lower costs from economies of scale.

- There is some interest within the electric-power sector in differentiated rate structures. Several utilities are experimenting with them. Further development of such structures should be encouraged.

- Current rate structures resemble those of telephone utilities. Residential consumers do not generally contribute their full share of utility costs. Conversely, industrial and commercial users pay more than their share.

- The widespread adoption of differentiated rate structures might allow better opportunities for the commercialization of new technologies, such as cogeneration and, in the more distant future, photovoltaics.

- The domestic electrical-machinery and electrotechnologies subsector is much less well developed than the power generation-transmission sector. It does very little R&D. The exception is AECL, whose CANDU system has brought major industrial benefits and involved substantial indigenous R&D. But the lack of a large domestic electrical-machinery and electrotechnology subsector seriously drains the Canadian economy. Canadian electric-power R&D might usefully address how to derive industrial benefits. The major Canadian electric utilities recognize the desirability of moving in this direction.

- To obtain and share technological information, several electric utilities have contributed to the Canadian Committee on Electro-technologies (CCE). CCE is a joint utility-industry-university group dedicated to technology diffusion, education, and information support across Canada, with strong links to corresponding groups overseas. CCE's mandate and activities make it a unique institution in Canada, and it is showing very promising results.

- An important new technology that might be encouraged by differentiated rate structures is so-called dual-energy or hybrid-heating systems. Such systems potentially offer major benefits to Canada in light of the country's severe winters and large-scale base-load generating potential. Up to 80 per cent of all Canadian space heating could be done by dual-energy systems at marginal, off-peak (lowest) electricity costs. This system is in widespread operation in parts of the United States and has had some success in Canada, notably through Hydro-Québec. It would also offer major opportunities for downstream industrial benefits.

# Background to the Sectoral Technology Strategy Series

In the emerging "new" economy of the 1990s, successful high-value businesses in advanced nations are being driven by innovation, propelled by spending on new products and processes. Their business strategies centre increasingly on specialized knowledge and skill in finding the right "fit" between their unique blend of core technologies and particular markets.

Where does Canada stand in this rapidly evolving new environment of changing linkages and relationships? The poor innovative capacity of Canadian industry has long been a concern of the Science Council of Canada, going back to its 1971 report *Innovation in a Cold Climate*. The Council re-emphasized this concern in 1988. It focused its attention on the potential for action at a sectoral level in its statement *A Sectoral Approach to Innovation*. It argued:

> There is growing recognition by industry and government in Canada of the key role played by technology and R&D in domestic and international competition. The Science Council considers that it is primarily the responsibility of industries to raise the degree of domestic technological sophistication and the level of R&D. Nevertheless, governments can help business to sustain long-term competitiveness both by building partnerships with individual firms and by generating consensus on the formulation of innovation strategies for the various industrial sectors. The intent is not for government to tell business what to do, but to facilitate business cooperation in a process of self-help. The process of building consensus on a strategy for a particular sector will involve close and on-going consultation with industries about the current role of technology and R&D in the sector, the opportunities foreseen, and the nature of the sources, stimuli, and forms of technological innovation. Obviously, to be successful, separate innovation strategies will be needed for each sector. The Science Council hopes that the process of building consensus will generate commitment and collective will concerning priorities, areas for cooperation, and agenda for action.

This 1988 statement proved to be an important step in the path that subsequently led the Council to undertake a major Sectoral Technology Strategy project.

In 1989, Industry, Science and Technology Canada, at a time of heightened concern for the state of Canadian competitiveness and serious questioning about the low level of Canada's gross expenditures on research and development as measured against other advanced countries, agreed to provide the main funding for this project. It also stipulated the selection of sectors on which it would like the project to focus.

Each report in this Sectoral Technology Strategy Series draws in part upon analyses commissioned by the Science Council of Canada from contractors, designed to reveal the key dynamics driving technological innovation in the sector and influencing company technology strategies. Each report has also benefited considerably from the comments and advice submitted by the many external reviewers from business, universities, and government, who are recognized in the Acknowledgements.

# Commentary on the Sectoral Technology Strategy Series and R&D Targets

The Sectoral Technology Strategy Series has analysed 15 Canadian sectors. On the basis of this experience, the Science Council of Canada makes the following points with regard to Canadian R&D performance and the issue of setting sectoral R&D targets.

- Canadian firms, when grouped by sectors, generally perform much less R&D than their trade competitors. Using the indicator of R&D as a percentage of sales, Canadian firms undertake R&D at a rate about one-third to one-half the rate of their leading international sectoral competitors. The notable exception among those sectors analysed is telecommunications.

- In some product lines or specific technologies certain absolute threshold levels of R&D and capital investment must be reached if the effort is to be considered to have a chance of making a commercial payback. High thresholds are apparent in some parts of sectors such as telecommunications (central office switches), automotive parts ("Tier 1" suppiier status), oil and gas (reformulated gasoline standards by refineries), and electronics (integrated circuit foundry). Such absolute thresholds cannot be clearly expressed as a percentage of sales.

- The reasons for the lower level of R&D spending by firms in most of the 15 Canadian sectors are: choice of business and technology strategy (which, in part, leave Canadian companies as essentially nonparticipants in many higher value-adding segments); the relatively small size of Canadian firms; the high absolute thresholds of R&D expenditure required to be a meaningful player, especially for innovative technology strategies; and the degree of foreign ownership of Canadian firms (especially important in the case of the automotive vehicles and parts sectors).

- The lack of R&D relative to other countries affects Canadian competitiveness, but it is only one of many factors, such as capital and labour costs, quality design, good marketing, and management, that interact to affect overall competitiveness. Nevertheless, the contribution of R&D, or more precisely, technology-based innovation, is becoming more pronounced throughout the global economy, and Canada continues to fall behind. The low level of R&D is especially detrimental to the capacity of Canadian resource-based sectors to compete with higher-value, differentiated products, leaving them vulnerable to adverse shifts in costs beyond their control, such as a higher exchange rate.

- Major potential does exist for Canadian industry to make additional R&D investments. However, fulfilling this potential depends heavily on the vision and capability of management to make strategic use of technology, to speed the firms' innovation process, to work more closely with suppliers and "demanding customers" all the way to the end of the product chain, and to build core capabilities in incremental innovation and R&D. Canadian firms have not yet fully grasped the implications of the emerging new "lean enterprise" or "agile producer" strategy. To follow this new strategy involves seeking to offer maximum value to customers. It requires integrating the skills base of a knowledgeable workforce with flexible management structures that stimulate cooperative initiatives within and between firms to match customer needs.

- The dominant technology strategies being followed by Canadian firms in these sectors are of adopt and adapt. Innovation technology strategies are not very extensive (telecommunications is again an example), and hardly any firms focus on breakthrough strategies to enhance competitiveness. Overall, these 15 sectors show little attempt at diversification out of existing product lines as opposed to making such products more efficiently.

- Governments can set sectoral R&D targets in the hope of stimulating enhanced industrial performance, shifts in business strategy, and greater commitment by the private sector to R&D. However, private sector R&D is only meaningfully undertaken in conjunction with a full complement of associated private and public sector actions ranging from improved design and production to finance and marketing. Doing more R&D will not be productive unless linked to a broader corporate technology strategy that is carefully designed to support the firm's business objectives. Otherwise, the corporation cannot, and will not, marshal the complementary investments required to reap the benefits of the R&D. It is the firm that must commit R&D resources.

- Setting sectoral R&D targets becomes more difficult as the boundaries between sectors are breaking down, through technological advances, regulatory change, and firm restructuring. Larger and more diversified firms that dominate modern industrial R&D perform R&D that might be allocated to any of several sectors. Examples include the textiles and materials R&D performed by large Japanese steel firms, the electronics R&D by automotive-vehicle firms, and the software R&D by telecommunications firms. Canadian governments have quite correctly encouraged higher levels of industrial R&D in Canada. In view of the rapid pace of scientific advances and technological change, plus the role of system interdependencies and synergies between technologies, setting R&D targets does not appear to be a task warranting the intensive effort, cooperation, and, ultimately, commitment that would be required by federal and provincial governments and private sector organizations.

# List of Sectoral Technology Strategy Series Reports

No. 1 The Canadian Telecommunications Sector
No. 2 The Canadian Automotive-Parts Sector
No. 3 The Canadian Iron and Steel Sector
No. 4 The Canadian Automotive-Vehicle Sector
No. 5 The Canadian Oil and Gas Sector
No. 6 The Canadian Petrochemicals and Resins Sector
No. 7 The Canadian Banking Sector
No. 8 The Canadian Nonferrous-Metals Sector
No. 9 The Canadian Forest-Products Sector
No. 10 The Canadian Machinery Sector
No. 11 The Canadian Food and Beverage Sector
No. 12 The Canadian Electric-Power Sector
No. 13 The Canadian Consulting-Engineering Sector
No. 14 The Canadian Electronics Sector
No. 15 The Canadian Computer Software and Services Sector

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# Introduction

The Canadian electric-power sector is dominated by several very large firms that perform a substantial level of R&D. Indeed, three of the top 10 performers of R&D in Canada are from this sector — Atomic Energy of Canada Ltd. (AECL), Ontario Hydro, and Hydro-Québec.

The sector is a success in several respects, including the fact that Canadians pay the lowest electricity prices of all countries belonging to the Organization for Economic Co-operation and Development (OECD). But whether electricity is nuclear, hydro, or fossil-fuel based, there is controversy over its environmental impact and whether current prices for electricity cover the full costs of production. And there is also controversy over whether these major firms, which are regulated monopolies, should be privatized and electricity production decentralized. Such a move would have important technological implications.

The main objective of this report is to indicate:

- the technology strategies of the leading Canadian firms;
- how the sector performs in R&D compared with foreign electric-power sectors;
- the major reasons for any differences; and
- how these differences affect competitiveness.

# Overview of the Global Electric-Power Sector

## Technology and Regulated Monopoly

The business of generating electric power has grown immensely over many decades and shows no sign of slowing down. Consumption in North America of fossil fuels — the predominant energy source — has grown very slowly or been stable since the oil crises of 1974 and 1979, but demand for electricity has continued to increase, giving it an ever larger share of the total North American energy market. In addition to its traditional markets of lighting and electric motors (for which alternative energy sources are not practical), it now competes with other energy sources in applications such as space heating and industrial process heat. This has led to greater public scrutiny of the methods of generating electricity, its price, and perhaps above all, its environmental impact and safety.

Electric power has traditionally been generated by regulated monopolies. Competition was deemed unrealistic, since electric-power service required individually wired connections from equipment at point of use back to the generating plant. It would have been impractical to have two or more separate, competing systems down every street or road and across every township or farm. There would have been massive duplication and exorbitant costs. But because of the monopolies, government regulation was required to prevent excessive pricing. In fact, it often made sense for governments themselves to own and operate the electric-power companies, and this is predominantly what has happened in Canada. Except for some utilities in Alberta and Prince Edward Island, electric-power companies are provincial government corporations. All over the globe there has been a pattern of creating regulated monopolies to generate electric power.

The regulated-monopoly structure of the electric-power sector also led to a noteworthy economic phenomenon brought about by advances in technology: economies of scale. Large, centralized generating plants produce the cheapest electricity. A typical single generator (for example, a nuclear reactor) has 600+ megawatts (MW) rated output. Usually a complete facility has at least four such generators, for a total of 2500 MW. Although large hydro sites and nuclear reactors have major up-front capital costs, their nonexistent (water) or low (uranium) fuel costs give them the lowest costs per kilowatt-hour in the long run. Accordingly, both R&D and utility construction have contributed to the increasing importance of these systems. In the United States, as the Roosevelt administration wrestled with the effects of the Great Depression, the megaprojects of the 1930s were the Tennessee Valley Authority power system in the east and the Grand Coulee and other electric-power dams in the west. After the Second World War, nuclear power developed as a generating source, spun off from the military atom bomb program.

In Canada there was no military program to support nuclear research, but the high level of industrialization that Canada gained in the war, plus large domestic reserves of uranium, led Canada to develop its own equivalent, but technically different, CANDU system. Later, in the early 1960s, the creation of the unified Hydro-Québec electric-power company led to massive hydro developments at Churchill Falls in Labrador and James Bay in Quebec. Moreover, utilities' own research identified future, potentially still more powerful, and conceivably more economical and safe generating and transmission systems, such as fusion and superconductivity.

Electricity prices generally fell in real terms throughout the 1960s and 1970s. The rate structures adopted by utilities appeared to indicate that economies of scale were indeed being realized.

But following the oil crisis of the 1970s, the rate structures and generating philosophy of electric utilities came into question, first in the United States, and then in Canada and elsewhere. Electric utilities faced the problem that the changes in relative energy costs, brought on by the Organization of Petroleum Exporting Countries (OPEC) cartel were both very abrupt and largely

unforeseen. Because of increased oil prices, utilities that used oil for generation (hardly at all in Canada, quite a lot in some U.S. jurisdictions) found that their operating costs went up in the years immediately following the oil crisis. But the possibilities of substituting electricity for oil and gas, plus the prospect based on experience that the real price of the electricity would continue to fall, meant that demand would probably rise noticeably. More non-oil generating facilities would be required. The huge capital investment required for these facilities had to be committed. But then in the early and middle 1980s, the combination of a falling reference price for oil, unexpectedly successful energy conservation, and the severe economic recession of 1981-1982 made for large surpluses of electric-power generating capacity. Despite these surpluses, electricity prices still rose. The committed capital costs had to be paid, regardless of whether the plant was used. The whole basis of electric-utility forecasting, planning, and generating came into question.

Particularly in the United States, the response to the rollercoaster ride of capacity shortages, capacity surpluses, and attendant changes in electricity prices was a return to free markets and a move away from regulated monopolies.

Around the world today, even in the centralized economies of the former communist world, there is movement toward free markets, which many believe are much more efficient than government planning in producing and allocating goods and services. The result is that economic sectors, once viewed as the exclusive province of government-owned or government-protected monopolies, are being deregulated and opened to competition. Telecommunications and banking are two sectors in which this liberalization is under way. (See Science Council of Canada Sectoral Technology Strategy Series, No. 1: *The Canadian Telecommunications Sector* and No. 7: *The Canadian Banking Sector*.) Electric power is a third.

## Market Competition and the Privatization Debate

This return to free markets has also led to a secondary debate on whether utilities should be privatized.

Although privatization is not necessary for, or synonymous with, free-market competition — sometimes freeing entry to an industry, or deregulation, is sufficient — it is emerging as an option for encouraging free-market competition in the electric-power sector. State-owned electric utilities were among the most common of the $185 billion worth of government assets that were privatized worldwide from 1984 through 1989.[1]

Electric-utility privatizations vary from the small, incremental type now present in most Canadian provinces (with small amounts of private power production allowed) and 'BOTs' (build-own-transfer schemes in which a private developer, over the life of the franchise — typically 20 to 35 years — will build, own, and then transfer the project back to the government) to larger-scale privatizations involving either the entire generating sector or the entire electricity system (generating plus transmission).[2]

A pamphlet published by Energy Probe describes more than 40 countries that are, in varying degrees, privatizing their electric-power systems.[3] This is a surprisingly large number. The following are just a few examples:

*The United States* — Historically, the U.S. electricity-supply industry consisted of hundreds of investor-owned utilities, each with an exclusive franchise to sell electricity in a defined geographic area. Thus, U.S. utilities were vertically integrated monopolies. Customers had no right to 'shop the grid' for cheaper electricity, and outside suppliers had no right to offer power to customers through the grid.

However, an important element of free-market competition was introduced with the U.S. *Public Utility Regulatory Policies Act.* Passed in response to the energy crisis of the 1970s, this act required regulated utilities to purchase power from qualifying facilities at "avoided cost." In some states, notably California, the prices and contract terms offered to qualifying facilities were so attractive, relative to the long-run marginal cost price that justifies new investment, that thousands of megawatts of new capacity were offered within a few years. Although the results were grossly inefficient in some cases, the potential for independent power supplies had been demonstrated to public officials, consumers, entrepreneurs, and even utilities themselves.[4]

With regulators and some utilities supporting the idea, competitive generation has developed to the point that much — perhaps most — of the new generating capacity in the United States is provided by nonutility suppliers. As a result, investment patterns have changed markedly in the U.S. electricity-supply industry. Even for utilities that still plan to build for themselves, the preferred way to develop new capacity in the 1990s is often with modular, staged, small projects or by extending the life of older units that generate less than 400 MW.

Based on traditional utility discount rates and treatment of risks, some of these options might appear to have higher per-unit costs over their lives than constructing larger units all at once. However, based on investment criteria more appropriate for a U.S. competitive market (in which investors, and not customers, bear investment risks), these options may seem reasonable.

*The United Kingdom* — Restructuring the U.K. electricity-supply industry has not been driven by pressure from consumers or independent suppliers as in the United States. Rather, the political agenda of the Conservative government has changed it. The electricity-supply industry is only one on a long list of government-owned industries being privatized.

In February 1988, the British government issued its White Paper, "Privatising Electricity," outlining plans for the electricity-supply industry, with the ambitious goal of beginning the sale of electricity suppliers in January 1990. Thus, in contrast with the restructuring process in the United States, the U.K. process is proceeding on a government plan and timetable, with the principal decisions being made by a few people.[5]

The old national electric-utility monopoly — the Central Electricity Generating Board — is being partitioned, and the major parts are being sold. Still in government hands is a national grid company, which operates the transmission system, and the nuclear-power generating plants.[6]

The new system introduces free-market competition into the U.K. electric-power sector. The privatized companies are National Power and PowerGen, which own all the non-nuclear-power generating capacity in Britain. But other companies are preparing to enter the sector. Texaco, for example, plans to build a £450 million ($900 million) gas-fuelled power generator in Wales and sell the power to the national system.[7]

Initially, the government intended to sell the nuclear plants as well. But its calculations showed that although the wholesale price of electricity on average is about 3.6 pence (approximately 7.2 Canadian cents) per kWh, the cost of privately produced nuclear power (including insurance premiums required for private-sector liability) could be as high as 9 pence (approximately 18 Canadian cents) per kWh. It was clear that the nuclear plants were uneconomical — and unsaleable.[8] Critics of nuclear power have used this as an example of the hidden costs built into the old monopoly.[9]

*Chile* — The government has sold 50 per cent of Chilquinta, an electricity-distribution company, and Chilgenor, an electricity-generation company. It privatized 34 per cent of Endesa, the electric utility, and plans to sell 30 per cent of the Colbun hydroelectric complex, as well as three regional power utilities of Empresa. The electric utility, Chilectrica, has been in private hands since 1985.

*China* — A $500 million coal-fired BOT power plant was completed in 1987.

*Austria* — the government sold 49 per cent of Verbundgesellschaft, the federal electricity authority, in the largest offering ever on the Vienna Stock Exchange, as well as EVN, a regional electricity company. Shares in other regional electric utilities have been sold, and privatization continues.

*Malaysia* — The government turned the National Electricity Board into a private company (STM) on 1 January 1990 and plans to sell it on the local market in 1991.

*New Zealand* — The government plans to privatize 55 power utilities and the $1.7 billion national power grid.

*Denmark* — Following a 1986 government decision, Denmark began to phase out its large generating facilities in favour of vastly increased cogeneration, mostly by municipal and industrial producers. Denmark's electricity sector is very decentralized, with some 120 electricity companies, about 20 generating companies, and 100 distribution companies. The generating companies are mostly partnerships; the distribution companies are cooperatives, municipal utilities, partnerships, independent companies, and limited-liability companies.[10]

These countries and others are fundamentally restructuring their electricity-supply industries. The different ways of restructuring reflect their different histories and political and institutional contexts. For these countries, the underlying economic and technological forces are similar. Whether or not a national debate goes so far as to include privatization specifically, these forces are driving electricity-supply industries around the world toward the same future: a more businesslike, competitive industry.

According to energy expert Dr. Larry Ruff of the London office of Putnam, Hayes & Bartlett, the privatization argument can be set out as follows:

> The trend toward commodity-like, capital-minimizing investment patterns in the electric supply industry is regarded by some as uneconomic, on the grounds that utility investment should be made safe so that economies of scale can be exploited fully to lower unit costs. But the notion that it can be "safe" to invest hundreds of millions of dollars in huge plants that take years to build, for a commodity market that cannot be predicted accurately, could in all likelihood only be maintained by a monopoly utility that enjoyed the advantage of being able to "tax" its rate payers to shift risks away from investors. There appears to be no fundamental economic reason that efficient investment and financial patterns should be much different in the electric supply industry than in other commodity industries like fertilizers and steel.[11]

Ruff continues:

> The most striking feature of the developing UK electricity supply industry [for example] is the nature and extent of the competition it appears likely to stimulate. Although the general presumption in the UK is that competition can develop only as far and as fast as significant amounts of new baseload capacity can be built, this presumption could be disastrously wrong. It will be easy for new entrants to get a "ticket" to the game, and just the threat of competition can drive down grossly inflated prices with amazing speed in a well-organized spot market with many players, each holding excess capacity.

There is no fundamental reason the U.K. electricity-supply industry cannot function efficiently as a competitive commodity industry. But it will be a very different electricity supply industry than has existed in any major industrial society to date.[12]

Ruff's argument links privatization with free-market competition. It suggests privatization is a positive option for achieving a positive goal: price competition.

But there is another side to this debate. Privatization is not necessarily synonymous with competitive markets. First, in the United States, utilities were often private. This situation did not bring about competitive markets. Electricity markets remained regulated monopolies. The principal reason for this lay in the technical constraints on transmission, distribution, and storage of electricity. A utility in Oregon might have lower costs than one near New York City, but being privately owned was still irrelevant to the practical engineering reality that transmission losses were insuperable beyond about 1000 miles. Hence, monopolies were inevitable. Similarly, the other examples of privatization do not necessarily demonstrate the existence of competitive markets. Privatizing a Chilean or Chinese utility does not necessarily alter practical realities of limited power-transport opportunities, that is, monopoly status is the only practicable option.

Second, even in the United Kingdom, where virtually all parts of the country could be supplied by power from some other national location (for example, a low-cost Scottish hydro facility could still compete with a Midlands coal-fired plant for the London market), competition is likely to be seriously limited because a newcomer will find it difficult to respond to any significant demand without committing heavy investments in new plant. This new generating capability must compete with existing plants that are already fully amortized and inevitably have much lower costs. And, indeed, electricity prices continue to rise in Britain.

Third, in a case-study comparison of electric-power utilities in France and New York State, Professor Robert Frost of the State University of New York concludes that the nationalized Électricité de France (EDF), which is a heavy user of nuclear technology and leads a deliberate electrification strategy for French industrial, commercial, and residential energy needs, has had a decided technological and economic edge over the mostly private New York State utility system.

> By nationalizing their electrical supply, the French have, as a nation, taken control over their energy and technological future in a highly strategic sector. At about 6.5¢ per kWh for new supply at the retail, domestic level, EDF — in a country without appreciable fossil fuels and highly limited hydro capacity — can underprice the US' current 8-9¢ per kWh rate. EDF has a highly rationalized and low-cost set of suppliers for its equipment, and in co-operation with other state agencies and private firms, French energy policy is well framed and solidly directed toward the future. Finally, from the perspective of technological development, the mechanisms are in place to initiate whatever new trajectories appear necessary.[13]

Frost goes on to suggest that, in contrast, the New York electric-utility sector has reached a technological impasse. Its nuclear program is substantially discredited, and its increased use of fossil-fuel technology is drawing fire for environmental reasons, especially global warming brought on by $CO_2$ emissions from fossil-fuel combustion. In sum, he says, American utilities, despite much privatization, have little sense of direction at present, and few of them can forecast how their energy demand will be met 10 years from now.

Privatization may be an option for bringing about either competition (and, hence, lower prices) or a full reflection of the total real monetary costs. It has received considerable attention recently in several countries. But as we shall see, privatization is not necessarily the only option, or even the best one.

# Overview of the Canadian Electric-Power Sector

## Big Business, Low Price

In Canada, electricity generation is big business. Indeed, Canada is the world's largest producer of hydroelectric power (314 TW/h). Canada's electric utilities estimate capital expenditures for 1985 to 1995 will total $71 billion. Fifty-seven per cent of this, or $40.5 billion, is being used to build new coal, nuclear, and large hydro generating stations; most of the rest is being spent on high-voltage transmission lines.[14]

Providing electric power in Canada presents major technical challenges. Some generating stations are in remote locations: for example, many major hydroelectric sites of Hydro-Québec, Manitoba Hydro, and B.C. Hydro are far from the major consumption centres. The length of Canadian transmission lines is scarcely exceeded anywhere in the world. In other cases, consumers are in very remote locations, for example, in small communities in the Yukon and Northwest Territories. These communities need dependable, small, local generators — with precisely the opposite technical demands of large, distant hydro sites.

At about 5¢/kWh, Canadians pay the lowest electrical energy price of all OECD countries, and among the lowest in the world.[15] Canadian rates are usually about half those in most of the United States and Europe — a striking difference. Canadian utilities point to this low price when they suggest their operations are in the best interests of both business and household consumers.

Critics disagree. They argue that Canadians pay a price for these lower rates through a variety of direct and indirect subsidies to utilities.[16] Most Canadian electric utilities, Alberta and Prince Edward Island excepted, are owned by provincial governments. As such, they receive tax privileges unequalled in other sectors of the economy. Even the regulated private utilities in Prince Edward Island and Alberta benefit from tax rebates and are effectively guaranteed a certain rate of return on their equity investment.[17] In effect, Canadian ratepayers guarantee the cost of operations, including debt and interest payments, of their electric utilities, whether they are public or private.[18] If any sector is given preferential treatment, for example, being exempted from being part of the tax base, it can be argued that other business and private taxpayers have to bear a correspondingly larger burden.

This argument has been illustrated by Jean-Thomas Bernard, economist and director of Université Laval's Groupe de recherche en économie de l'énergie (GREEN). He suggests that if Canadian electrical utilities were treated as private companies, that is, if they were expected to have a competitive rate of return, pay the same taxes as other firms, and pay more realistic fees for hydro resources, the price of electricity would be substantially higher. Specifically, the price of electricity would increase by an estimated 44 per cent in Quebec, 65 per cent in Ontario, and 54 per cent in British Columbia.[19] These figures are controversial, but they do illustrate the argument that rates may not reflect all costs.

There are two arguments in favour of Canada's low electricity rates. First, they make Canadian industry more competitive by reducing the costs of energy; second, they favour establishment of industries that are heavy consumers of electricity, such as metal refining.[20] In particular, there appears to be a worldwide increase in the use of light metals such as aluminum and magnesium, which require more electricity for processing than other common materials. In the future the trend could be toward using other light metals, such as titanium. Accordingly, attracting these light-metals industries might be a promising strategy. (See Science Council of Canada Sectoral Technology Strategy Series, No. 8: *The Canadian Nonferrous-Metals Sector*.) Moreover, Canadian electricity rates could rise considerably and still remain cheaper than those in the United States, Europe, or Japan. Finally, it is noteworthy that consumption of electricity continues to grow, even in high-cost locations like Japan; this indicates that

electricity is a high-quality, strategic energy source. If Canada has a cost advantage over trade competitors in electricity generation, then it may be able to innovate and adopt the new technologies that use electricity to the country's strategic competitive advantage.

There are, however, several arguments against these low electricity rates if they do not reflect real costs.[21] One is that low rates tend to encourage energy waste rather than energy efficiency. An artificially low price encourages consumption and stimulates the need for more generating stations.[22]

Moreover, utilities consume a great amount of capital. Hydro-Québec's investments represent on average 8 to 12 per cent of the total annual industrial investment of Quebec. Ontario Hydro and Hydro-Québec together have debts of about $65 billion. It is therefore essential to ensure that the return on this immense capital be maximized. Some critics argue this is presently not the case.[23]

Similarly, critics argue that, as Crown monopolies, utilities are not generating any return to shareholders; nor are they producing tax revenue. This represents yet another loss to taxpayers.[24]

However, these arguments are debatable. Some utilities apparently are, or have been, returning dividends to their provincial governments in one form or another, and the lower price may in itself represent a dividend of sorts to the ultimate shareholder, the Canadian taxpayer.

Nevertheless, Canadian utilities, particularly the two largest, Ontario Hydro and Hydro-Québec, have been the subject of some controversy in recent years.

In Ontario Hydro's case, the 1991 government has put a moratorium on further nuclear development while it considers the province's energy options. Some groups such as Energy Probe are urging the province to go the privatization route.

Ontario Hydro plans to invest $200 billion ($170 billion of it borrowed) over the next 25 years, and Energy Probe argues that these funds might be more profitably used elsewhere in the economy.[25] The lobby group says that if Ontario Hydro had to respond to market forces — and nonsubsidized power prices — much of the spending might not even be necessary.[26] Indeed, according to Energy Probe, if Ontario Hydro had to meet market-based return on capital, earn a profit, and pay dividends and taxes like any other corporation, the returns to the economy would be significant. Based on Energy Probe's calculations, despite higher electricity prices, the benefits would be about $500 per household per year.[27] Moreover, Energy Probe points to Ontario Hydro's recent announcements of large rate increases for 1992 as evidence that its nuclear program is not turning out to be economical as the utility claims.

A solution Energy Probe is proposing is decentralization and privatization of electricity production in Ontario:

> Ontario's energy needs over the next 25 years would be best met through a decentralized supply system characterized by full cost internalization for social, environmental, and economic costs; and by equal access to the grid for any and all suppliers, public and private. Ontario Hydro would remain a Crown monopoly, but it would be regulated and its role limited to that of a carrier and broker. There would be divestiture of Ontario Hydro's saleable generating assets (hydraulic and fossil), and restructuring of its remaining generating assets.[28]

The Energy Probe privatization plan for Ontario Hydro is similar to the program in Britain described earlier.

Hydro-Québec is facing similar challenges. The utility is currently waging a legal battle to construct the 3168 MW Great Whale hydroelectric project. The utility faces five lawsuits launched by project opponents, and it must pass federal and provincial environmental reviews before it can proceed with the $12.7 billion development, which is just the first part of the $40-billion James Bay Phase Two project to be built over the next decade.[29]

Some Quebec energy analysts and economists doubt whether the project makes financial sense for the province. For example, Pierre Lamonde of the Université de Québec à Montréal and

Jean-Thomas Bernard of Université Laval have criticized Hydro-Québec for the bargain-basement prices it offers some Quebec industries and export customers.[30] The utility attracts aluminum and other smelters to the province's north shore by guaranteeing a supply of electricity, often over a 20- to 25-year span, at a rate that is tied to the spot price in the metals markets. Bernard, director of GREEN, claims the Hydro-Québec contracts unjustifiably subsidize primary-metals fabricators. "Instead of taking that electricity and selling it to the export market for six cents a kilowatt/hour, we're selling it for two or three cents. Under contracts with the four aluminum smelters, we're losing $300 million a year in revenue. That's a lot over 25 years."[31] Some environmentalists oppose the risk-sharing contracts because they feel that the deals boost energy consumption and force Hydro-Québec to undertake massive development, such as the James Bay project.

The rate structure negotiated by Hydro-Québec with at least some metals refiners is especially noteworthy. The rate Hydro-Québec charges for electricity is a function of metal price. In effect, the utility is sharing in the profits or losses of metals markets. The latter are highly cyclical; it is not unusual for refiners to suffer losses over some years in the course of an ordinary business cycle. This was, for example, the case in the 1982-1985 period, and it seems to be true also in the current 1990-1991 recession. Of course, the profits metals producers make during the better years more than offset the losses of the poor years, and it can also be argued that Hydro-Québec is responding to market forces by following such a rate structure — obviously the metal refiners themselves have to risk their own investments. However, the contracts give the appearance of an unfair subsidy and may prove subject to countervailing actions by the U.S. government.

Moreover, it could be argued that Hydro-Québec's standing and future investments in low-cost hydro generation offer major potential for new industries. For example, robotized flexible manufacturing systems (FMS) are, naturally, based on electric power for materials handling, welding, and other assembly actions. Hydro-Québec's low costs might attract such new-technology industries.

But other Quebec economists, for example Hélène Connor-Lajambe, have said that the money invested in hydroelectric development would be better spent in less capital-intensive sectors.[32] Lower tariffs on power no doubt attract both domestic and foreign-owned metal manufacturers; however, according to Connor-Lajambe, energy-hungry aluminum operations in Quebec tend to produce ingots that are shipped south for processing into manufactured products. Making ingots is capital intensive; turning them into finished products is labour intensive. Connor-Lajambe argues that Hydro-Québec's cheap-energy policy is in effect subsidizing jobs in the United States: exporting power keeps the Quebec economy "chained to resource production while stimulating manufacturing and high-tech jobs elsewhere."[33]

In Canada the exporting of raw or semifinished materials, instead of finished goods, is controversial. Current evidence indicates, as Connor-Lajambe suggests, that an industrial structure built on upstream processing of raw materials is both capital intensive and vulnerable. The high capital costs of processing limit employment, and new substitutions for many materials, brought about by new technology, can drastically undermine traditional product lines. (See Science Council of Canada Sectorial Technology Strategy Series, No. 3: *The Canadian Iron and Steel Sector*, and No. 8: *The Canadian Nonferrous-Metals Sector*.)

Another argument casts doubt on the wisdom of a strategy of capitalizing on metal processing because of Canada's low-cost electricity. This is the problem of having to import the required machinery. In brief, Canada has a weak machinery sector and imports three times as much as it exports; as the Canadian economy expands in the course of ordinary business cycles, jobs are lost in Canada because firms must import the machinery they require. It is a major structural weakness of the Canadian economy. (For a more detailed discussion of this problem, see Science Council of Canada Sectoral Technology Strategy Series, No. 10: *The Canadian Machinery Sector*.)

Development of a strong electric-power sector has contributed little to development of a related electrical-machinery sector. Expansion of electric power and downstream metals semifabrication could subsidize jobs indirectly in the United States and overseas to a great degree, despite high efficiency and profits returning directly to the corporations concerned. Lastly, it remains to be seen whether low rates for electricity will be enough to attract new industries, such as manufacturing using robotized FMS, to Canada.

Some analysts argue that conservation could offset Quebec's energy demands, create more jobs, and cost less than producing new energy through megaprojects.[34] Ian Goodman, a Boston economist, produced a study for the Crees last year that concluded the province would not require additional energy for the next 20 years if Hydro-Québec implemented an aggressive conservation program.[35] Considering the success of energy-saving programs in the United States, Goodman now says that estimate was modest.[36]

"With a good conservation program, you could achieve a reduction [in demand] of 15 per cent in 10 years. If Hydro-Québec is willing to invest $12.6 billion into a conservation program, for that kind of money you could save at least 6000 megawatts [almost twice the capacity of Great Whale]," Mr. Goodman says.[37] However, a 15 per cent reduction appears extremely ambitious.

Hydro-Québec plans to spend $62 billion on Great Whale and other new projects this decade. Those billions will be added to the existing $23 billion debt.[38] Critics argue that the high debt load compromises the province's borrowing power for other projects and drives up interest rates.[39] Hydro-Québec forecasts the province's future energy requirements will increase by 2.6 per cent per year.[40] Some critics even claim this is an overestimate for the future, although, in general, electricity demand has grown by at least this much each year for the past 15 years.

On balance, there are some direct advantages to low electricity rates, but whether the Canadian economy suitably captures the industrial benefits from competitive electricity prices is questionable.

## The Privatization Option in Canada

There is no consensus in Canada on the privatization option for electric utilities.

Canadian utilities have built some of the world's largest power plants, but evidence has also shown that they have fared poorly at constructing and operating small generating facilities. As a result, the utilities have concluded that technologies such as small hydro, wind, and wood-chip cogeneration are uneconomical.

What is uneconomical to some, however, is a profitable business to others. At least some experience from across Canada illustrates this point.[41]

For example, in 1984, Nova Scotia Power Corporation estimated the cost of constructing a 225 kW hydro project at Melford Brook, Nova Scotia, would be approximately $950 000. The utility justifiably considered this far too expensive to proceed.[42]

However, a local private developer, Black River Hydro Ltd., completed construction and delivered the same 225 kW for less than $250 000. Furthermore, the facility has been generating at full capacity 99 hours out of 100. This is extraordinarily good. In technical terms, the plant has run at a capacity factor of slightly more than 99 per cent. (Capacity factor is the index of what the plant actually produced compared with the theoretical output it would produce if it ran at its rated maximum output continuously.) This capacity factor is higher than that of any other generating station in Nova Scotia.[43]

In 1983, Ontario Hydro decided to divest itself of an 800 kW site in Carleton County near Ottawa. The site, according to Ontario Hydro, could no longer be operated economically, and a public tender to dismantle it was issued. Instead, a newly formed company, Galetta Power, rehabilitated the

old station for less than $200 000. In doing so, the firm greatly improved the station's performance, increasing its electricity output by 49 per cent. The facility can be expected to provide low-cost power to Ontario ratepayers for years to come.[44]

Another firm, McDonald Ranch and Lumber of Grasmere, British Columbia, further demonstrates how small business can build cost-effective projects. A study commissioned by Energy, Mines and Resources Canada estimated the cost of developing a 400 kW hydro site near the company's lumber operation at approximately $870 000. In 1984, using refurbished equipment and employing local labour and engineering, the firm completed construction of the facility for $90 000. Financing was provided entirely by the private sector.[45]

Of course, not all private power projects show such dramatic savings. These and similar projects do, however, demonstrate that the private sector is willing to invest in electrical generation in Canada.

Indeed, according to a 1987 study by Passmore Associates International of Ottawa, many entrepreneurs are waiting for changes in government policy so they can make capital investments in private energy projects. Passmore Associates claims that "private power could, if given the opportunity, generate more than $5 billion of investment in Canada and create 50 000 regionally dispersed jobs."[46]

Moreover, unlike public and private utilities, private power producers may not require federal or provincial debt guarantees, low-cost loans, or major long-term R&D subsidies.[47] But, on the other hand, they benefit from guaranteed prices, existing transmission and distribution networks, and R&D already established by the utility.

All Canadian utilities currently permit private power producers to connect to their systems. Unfortunately, the power purchase rates and contract terms and conditions offered by utilities discourage all but a few companies from entering the power-production business. Indeed, some Canadian utilities pay nothing for the electricity produced by private generators, while others pay on the basis of fuel savings (system marginal costs) only.[48]

Accordingly, despite current low electricity prices in Canada, there seems to be evidence that ratepayers might be better off if electricity generation in Canada were opened to competition from private industry.[49]

Whether this evidence is convincing is another question. First, it is entirely anecdotal. Second, while it illustrates that large organizations should not engage in small projects, it does not show that small organizations are necessarily good at engaging in large projects, either. Yet much bigger total generating capacity is needed, for any province in Canada, than the scale provided by these examples. In sum, the privatization debate, while profound for technology strategies, is as yet inconclusive in Canada.

But there is a more profitable perspective for discussing the future of the electric-power sector and for considering appropriate technology strategies. This different perspective builds on an analysis of the market for electric power. It rests on an unusual but immensely significant technological indicator: the load factor.

# A Major Technological Issue: The Problem of the Load Factor

The central technological problem facing the electric-power sector is that electricity cannot be stored.

But the demand for electricity in Canada is not constant. It fluctuates hour by hour (less at 14:00 than at 18:00), night and day (less when people sleep, more during daylight activity), and especially season by season (less in the spring and fall, more in winter, less or intermediate in summer). The index that electric utilities use to express this fluctuation is called the load factor.

Since electricity cannot be stored, a utility has to provide adequate capacity to meet demand at all times, including peaks, however brief and infrequent. This leads to elaborate mixes of different types of generating plants.

## Load Factor and Generating Mix

Utilities calculate their generating-plant requirements from the load-duration curve, which expresses the proportion of total load that is sustained at any moment throughout the year.

As the name suggests, base-load generating capacity is that which is in operation virtually all the time. The base load is the more-or-less constant part of the total load on a generating plant — it equals demand that is continuous. Probably 55 per cent of all generating plants in Canada can be characterized as base load. The big hydro sites with so-called annual water storage and all nuclear reactors are in this category. Intermediate plant (about 35 per cent of all capacity, generally smaller hydro or coal fired) is in operation some of the time, and peaking plant (about 10 per cent of capacity, often oil or gas fired) comes into operation only infrequently. The distribution of a utility's load (among base-load, intermediate, and peaking components) determines the appropriate mix of equipment it requires.

Not all generating capacity has the same cost structure. For example, if there is a high constant demand for power, the most cost-effective equipment in the long run will always have a low fuel or operating cost even if it has high capital cost. This type of equipment is ideal for base-load power. Since, being base load, it runs continuously, it will inevitably have a high capacity factor. By comparison, intermediate and peaking equipment may actually have a higher cost per unit of output; however, because the capital costs of such equipment are lower, the utility will find it the most cost effective for relatively infrequent use. In other words, it is uneconomical to let a large hydro site or a reactor stand idle because it is so capital intensive and the fuel to run it comparatively inexpensive. This is not, however, the case for relatively less capital-intensive coal boilers or combustion turbines (typical intermediate and peaking generators, respectively). The latter can justifiably run at lower capacity factors. The mix of equipment that utilities choose depends on their specific load characteristics — the load factor — and will, in turn, affect the total cost of electricity. In the long run, base-load equipment gives the cheapest electricity, providing, of course, that there is a large and assured market. The question of the consistency over time of electrical load and generation is a major issue.

## Generating Mix and Electricity Costs

Table 1 illustrates what different load and capacity factors imply for a utility's costs when a decision has to be made concerning the acquisition of new equipment. In this table, system A is characterized as 'all-base-load' one; it represents a very efficient system running at 70 per cent capacity. This high

capacity factor means the load factor must also be correspondingly high. By contrast, system B has a load factor more typical of recent Canadian or U.S. ones; in fact, the model assumes a system running at (by current load standards) only average efficiency — a 46 per cent capacity factor. These figures represent hypothetical systems available in 1992 at current average costs. It is noteworthy how the figures in Table 1 straddle existing 1991 and projected 1992 electricity prices in Canada quite well.

System A — the high-efficiency system — uses equipment that operates most economically in the long run. Examples of such a system include large hydro developments with annual water storage or nuclear (CANDU) reactors. The major expense of this system is capital carrying charges. Each current kilowatt of generating capacity requires an investment of $1200 and an additional $1000 for transmission and distribution equipment.[50] (In fact, if one were building a new kilowatt of base-load capacity in 1992, the cost would be approximately double these figures; but owing to utilities' conventional accounting system of averaging all costs over time, the mix of older and newer equipment effectively reduces the current average cost.)

In Table 1, capital charges have been annualized using a factor for real 'use of capital' of 10 per cent. Real use of capital is more than just real interest rate, as it also includes amortization of principal. For a 30-year amortization, which is representative of utility investments, it would correspond to an 8 per cent real interest rate. This figure is higher than that used by utilities themselves: they usually use a discount rate of 6 per cent real interest. However, the figure of 10 per cent for real use of capital has been used in cost-benefit studies by the federal government on several occasions to represent a credible real annual cost of capital investment.[51] Moreover, some equipment (for example, transmission and distribution facilities) may not last as long as generating plants and should therefore be amortized over a shorter period — say 20 years. This would imply a real interest rate in our example of about 6 per cent. Hence, these figures should be taken here as reasonable, if not definitive, cost accounting. Accordingly, the yearly cost of the standing investment of $2200/kW would be $220. But this is a high-efficiency system running at 70 per cent capacity factor; as shown in Table 1, 1 kW of generating, transmission, and distribution plant would provide 6132 kWh/year at an average cost of 3.59¢/kWh. The costs for fuel, operations, and maintenance are a relatively small proportion of the calculated all-in cost of 4.13¢/kWh.

By contrast, system B, running at 46 per cent capacity factor, has notably higher unit costs. The type of generating plant is different from that in system A. It contains three elements — a base-load component, an intermediate component, and a peaking component. The base-load component is the same capital-intensive type of plant as in system A. However, it represents only 55 per cent of the weighted kilowatt of generating capacity in this system. The intermediate component (35 per cent) and peaking component (10 per cent) represent markedly lower weighted capital-investment costs. Because a coal-fired intermediate plant is technically much simpler, producing a kilowatt requires much less investment than a kilowatt produced by a nuclear or large hydro plant — a representative estimate is $500/kW — and, at 35 per cent of the weighted mix, only $165 need be assigned to its share in this hypothetical kilowatt of generating-plant investment. The peaking component is even less capital intensive: at 10 per cent of the weighted total, only $30 need be assigned to it in standing investment.

Overall, the mixed system, B, has lower standing capital costs. Including capital for transmission and distribution (same as for system A), the total capital investment is assessed at $1855/kW; if a consistent 10 per cent real use-of-capital factor is used, annual carrying charges would be $185.

However, this system runs at much lower efficiency — only 46 per cent capacity factor — and, hence, all these costs have to be amortized against much less total output than was projected for system A — only 4030 kWh/year, or 4.59¢/kWh. Although the actual capital cost is lower for the mixed than for the base-load system, the difference is not nearly enough to offset the lower efficiency as determined by the poorer capacity factor.

Table 1. A representative cost-structure comparison per kilowatt-hour (existing average)

| System A: an all-base-load (high-efficiency) system running at 70% capacity | | System B: a currently representative system using typical mix of equipment running at 46% capacity | |
|---|---|---|---|
| I. Capital costs per kilowatt of generating plant | | I. Capital costs per weighted kilowatt of generating plant | |
| $1 200 (nuclear or large hydro) | | 55% $660 Base-load component (nuclear or large hydro) | |
| | | 35% $165 Intermediate component (coal, hydro) | |
| | | 10% $ 30 Peaking component (turbines) | |
| | | $855 Total | |
| II. Capital costs of transmission and distribution | | II. Capital costs of transmission and distribution | |
| $1 000 | | $1 000 | |
| Total capital costs: $2 200 | | Total capital costs: $1 855 | |
| III. | | III. | |
| (a) Estimated annual real use-of-capital costs (10%) | | (a) Estimated annual real use-of-capital costs (10%) | |
| = $220 | | = $185 | |
| At 70% capacity factor, this has to be amortized against 6 132 kWh | 3.59¢/kWh | At 46% capacity factor, this has to be amortized against 4 030 kWh | 4.59¢/kWh |
| (b) Fuel and operating costs | | (b) Fuel, operating and maintenance costs (weighted kWh) | |
| Uranium at $100/kg 0.8% burn-up and 30% efficiency | 0.19¢/kWh | Uranium (55%) | 0.10¢/kWh |
| | | Coal at $30/tonne (35%) | 0.47¢/kWh |
| | | Turbines (oil at $30/bbl) (10%) | 0.58¢/kWh |
| (c) Maintenance at 10% of capital costs | 0.35¢/kWh | | |
| Grand total costs | 4.13¢/kWh | Grand total costs | 5.74¢/kWh |

Source: Rick Clayton, *Electric/Oil Hybrid Heating Systems* (Ottawa: Ministry of State for Science and Technology, 1984).

Furthermore, the fuel, operating, and maintenance costs for system B are higher. Operating expenses per kilowatt-hour of output are greater than those for hydro or nuclear plants. Overall, system B produces power at about 5.74¢/kWh.

These figures represent average total costs for a utility in 1992. A recently commissioned plant is likely to cost more than an older one owing to inflation, but electric utilities roll in all their costs over time to obtain an average. Nevertheless, these figures show the cost implications and usage trends that utilities need to consider in assessing their need for capital renewal and expansion in light of their forecasted loads.

The high-efficiency system, A, was postulated to run at 70 per cent capacity. For a plant to achieve this, the load placed on it would have to be remarkably uniform. An electric utility normally has reserve capacity (plant) to meet unscheduled outages of equipment (breakdowns). This reserve usually is equal to 25 per cent of the total generating plant. Since the backup plant is likely to stay idle most of the time, if its capacity is factored into an overall capacity factor of 70 per cent the load factor from the demand placed upon all of the equipment must be even higher — probably 80-85 per cent. By contrast, a 46 per cent capacity factor, a typical, recent Canadian average, would imply a load factor of about 65 per cent. But a great deal of equipment — not just that in reserve — will inevitably stand idle a large portion of the time.

It is clearly in the financial interests of electric utilities to improve their capacity factors by having continuous stable loads.

Accordingly, the technological issue that drives the generating philosophy of utilities is the load factor. No-one can specify the costs of generating electric power unless he or she specifies the load factor.

High load factors argue for large, centralized generating facilities such as James Bay hydro and CANDU nuclear reactors. They run continuously. Low load factors, however, argue for modular, small-scale generators that run only when required.

It is sometimes argued that hydraulic-based systems, such as in Quebec, Manitoba, and British Columbia, are not as sensitive to load factors as the thermal systems in Ontario, New Brunswick, Nova Scotia, Saskatchewan, Alberta, and other provinces. It can be argued that, in effect, the water standing behind the dam is a form of energy storage, and, since in theory it can be drawn down as required, it can match any load profile.

Hydraulic generation is thus more flexible than thermal generation, but even hydraulic systems face limitations. First, water flows in Canada are inevitably seasonal. Typically, more water becomes available in the spring as snow cover melts. Unfortunately, the spring is the low season for electricity demand. Utilities accordingly often have to store water for most of the year — hydro sites need to have so-called annual storage. This, in turn, makes month-to-month forecasting very challenging. Second, there can be periodic droughts — a problem B.C. Hydro faces, for instance. Third, there may not be enough room to simply add more turbines below the dam. Even hydraulic-based systems benefit from high and constant load factors. Hydro-Québec, for example, uses its major stream flows at Churchill Falls and James Bay continuously to generate base-load power.

What is noteworthy about the load factor is that it is little known or understood by most Canadians outside the power utilities or related organizations. There is likely a good reason for its lack of appreciation by most consumers — the undifferentiated rate structures Canadian electric utilities have usually put in place.

## Load Factor and Pricing Strategies

In the industrial and commercial sectors, electricity prices are usually a function of two variables: demand and energy. Demand is the number of kilowatts of generating plant any utility has to commit to the user at peak demand; energy is the number of kilowatt-hours consumed. Users consuming electricity uniformly will have the lowest overall electricity costs, since they will get the maximum number of energy kilowatt-hours from any given number of demand kilowatts; but users have still only a modest incentive to arrange a high load factor, because the cost ratio between the two is not progressive, even though the costs to the utility to generate the power are closely proportional to the load factor.

Household consumers do not have even this modest degree of price differentiation. They have virtually a single reference electricity price. In Canada at the present time this price is about 5¢/kWh. It can be argued that this is quite misleading. At 17:00 on the coldest working day in January, peaking power has to be brought on line, and the ready reserve will be actually spinning, although not actually generating revenue — just standing by. Costs to a utility at such peak-load times can be 50¢/kWh — 10 times greater than posted rates. On the other hand, at 4:00 on the Sunday morning of the Labour Day long weekend in September — not even air-conditioners are on at this time — the cost of power is virtually zero. But among household consumers, no-one knows either way.

Exactly the same problem afflicts other capital-intensive, variable-load industries. A good example is the airline industry. At any given moment there may be four or five different fares between any pair of Canadian cities, depending on the season, day of the week, advance booking, and so on. The lowest fares are off peak: the airline is committed to sending an airplane to Vancouver or wherever anyway. Any revenue is a bonus. Airlines have derived elaborate 'yield-analysis' pricing programs designed to optimize total resources relative to total costs. The goal of these pricing programs is to ensure that the fare of the last passenger carried just covers any extra cost the airline incurs for the passenger. The load-duration curves of electric utilities are analogous to the airlines' yield-analysis curves, but there has been little attempt to develop similarly sophisticated pricing programs.

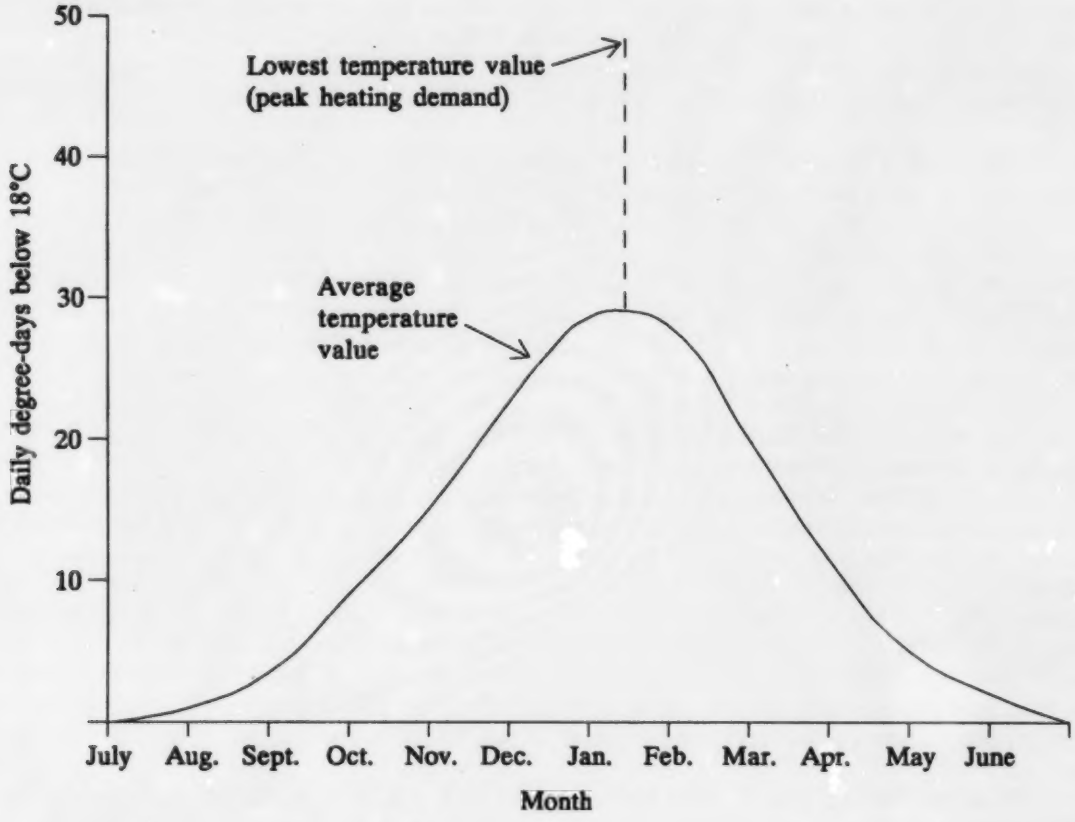
A single price for electricity may also hamper conservation efforts. Ontario Hydro, for example, would like to reduce total peak electricity demand by 6000 MW. The utility is even distributing free, more efficient light bulbs to consumers. But without any significant price signals, are such efforts meaningful?

In the past the misleading pricing structure of Canadian utilities led to very expensive and uneconomical uses for electricity, such as all-electric space heating. As we shall see, all-electric heating usefully illustrates the problems of averaging all costs into one undifferentiated rate.

***Case Study: The High Cost of All-Electric Heating***

All-electric space heating is common in Canada, despite being basically very costly. Consumers do not see the real costs. The high cost of all-electric space heating arises from the severity of Canadian winters. Wide and intense cold fronts can extend across half the country for several days at a time. Local temperatures can drop to -30°C and even -40°C, or 20-30°C lower than the January norm. Figure 1 shows a typical degree-day plot for Ottawa. The dotted line traces the large gap between the lowest temperature (peak heating demand) and the average temperature of the coldest month (January). This is the nub of the problem with all-electric space-heating systems: to satisfy customers' needs, utilities must have enough capacity in their generating plants (including adequate reserve) and in their transmission and distribution grids to meet the worst situation, even if it occurs only once a year. In other words, all-electric space heating has a very poor load factor. Existing data on the climate show

Figure 1. A representative Canadian degree-day plot




that under Canadian conditions, space-heating demand has a 27 per cent load factor. Compare this with the overall diversified residential load on a generating plant, which is approximately 35 per cent, and the average overall utility load factor, which is 65 per cent.[52] Typical all-electric space-heating systems drive the load factor, from utilities' point of view, in the wrong direction — away from base-load generation and toward peak-load generation.

For some time Canadian utilities have offset this irregular space-heating demand through load diversity. When electricity met only a very small proportion of the total space-heating demand, load diversity helped smooth the diurnal load variations. For example, although it is generally colder at night, which means that more electricity is needed for space heating, night-time demand from other uses is less. This load diversity flattens the diurnal load curve. In fact, most Canadian utilities have had a flat January load for many years. But it should be stressed that the load is flat at a high level of use. This means that if the use of all-electric space heating increases in the future, there would be little room to offset the new space-heating demand peak through load diversity.

Because Canadian utilities are already operating at a high level in winter, heavy additional demand for electrical space heating would add new peaks to an already high demand. The result would be a synchronized, as distinct from diversified, load.

Synchronized loads are disastrous. Utilities would be forced to buy considerably more equipment just to meet a higher January peak. There would not be a corresponding demand at other times of the year, and the annual capacity factor of the system would decline steeply. This would translate directly into higher average generating costs, and consumers would pay higher rates. Unfortunately, space heating is the major new identifiable market that the electric-power sector could serve.

According to Ontario Hydro, even after allowing for opportunities for load diversity, an average-sized house in southern Ontario heated only by electricity requires more than 9 kW of dedicated power at point of use just for space heating during peak demand (that is, coldest) conditions. This is more than three times greater than the diversified peak-load demand (3 kW) from a house that is not heated by electricity. Furthermore, by Canadian standards, southern Ontario has a relatively mild climate. Colder locations would place heavier demands on the electric grid. Additionally, a power demand of approximately 9 kW may not represent the full requirement from the electric system. An electric utility has to be prepared to lose up to 10 per cent of its power in transmission and distribution. It also has to maintain an additional 20 per cent reserve in case of equipment breakdown. Lastly, large stationary cold fronts often extend beyond the service area of one utility, a fact that limits its ability to use climatic diversity to reduce peak demand.

Taking all these factors together, if it is operating at capacity under climatic conditions such as those prevailing in most of Ontario, a utility normally has to dedicate 10 kW or more at the generating plant for each electrically heated house.[53] By contrast, without electric space heating, the average residential diversified peak demand (which establishes the utility's requirement for dedicated generating plant) is only 3 kW or less — just one-quarter as great. Ontario Hydro has been quoted as saying it costs $50 000 to build enough new generating capacity to supply one electrically heated house.[54] At a 10 per cent annual rate for use of capital, this capacity costs the utility about $5000 each year. Fuel and operating costs would be additional. But even allowing for an annual electricity sale of 20 000 kWh to an electrically heated house, at 5¢/kWh the revenue would be only $1000 each year.

Of course, the high costs of such inefficient uses of electricity as all-electric space heating are hidden by the convention of one price for electricity based on an average cost. It does not help the utilities' case for their existing generating philosophy.

In sum, the load factor is a major determining influence on the choice of generation technology. Economies of scale do exist in electric power, but only if demand is continuous, that is, at high load factors. However, as long as new, large-scale electricity applications are limited to markets such as electric space heating, whose load profile is determined by exogenous factors like the weather, the load factor will deteriorate, and the case for both smaller-scale facilities and privatization will be stronger.

But the case for large, centralized generation would also be immeasurably stronger if utilities could realistically project more continuous demand for electric power. Even better would be a load that a utility could accept or reject at its option — an interruptible load that would 'fill the valley' in the total load-duration curve and justify more base-load power. Are Canadian utilities searching out such loads? Their R&D programs should provide a clue.

# Canadian Electric-Power R&D in a Global Context

## Organization of R&D[55]

Electric-utility R&D is structured in various ways. In many countries (France, Germany, Sweden, Italy, Japan), R&D is integrated into the internal structures of public utilities; this is also the case with both Hydro-Québec and Ontario Hydro. Sometimes an R&D company is affiliated with the utility — for example, Powertec is the research subsidiary of B.C. Hydro. Finally, in Britain the Electric Research & Development Centre has become a completely autonomous research organization, selling its services to British utilities in competition with other research performers.

Both the United States and Japan have important cooperative research organizations for the electric-utility industry. U.S. utilities rely to a great extent on the Electric Power Research Institute (EPRI), and the U.S. government finances a lot of strategic research: for example, it invests $500 million annually in nuclear fusion. In Japan, utilities contribute substantially to the cooperative research organization Central Research Institute of Electric Power Industry, in addition to their own internal R&D.

There are cooperative research organizations in Sweden and Germany, but they have limited budgets. In Canada, the Canadian Electrical Association plays a role similar to that of EPRI in the United States but with a much smaller budget.

## R&D Objectives[56]

In all countries examined for this report (Canada, United States, Japan, United Kingdom, Belgium, France, Germany, Sweden, and Italy), R&D is concerned primarily with improving the utility's operational performance. For example, an estimated 75 per cent of Hydro-Québec's research is in response to short- or medium-term operational needs. Similarly, Ontario Hydro dedicates most of its research to near-term technical issues and problems.

Generally, utilities do not perform theoretical or fundamental research, which is left to universities and national laboratories. On the other hand, although utilities do perform practical research useful in their own operations, relatively little effort is dedicated to commercializing the products of their research.

## Major Research Areas[57]

Utilities concentrate on R&D that is appropriate for their own generation and transmission systems. Utilities that rely heavily on nuclear fuel, such as Électricité de France (EDF) and Ontario Hydro, dedicate much of their R&D to nuclear energy. Hydro-Québec concentrates on long-distance transmission and prolonging the useful life of hydroelectric facilities.

Nevertheless, it is possible to discern widespread tendencies in R&D across the sector. There is general interest in:

- the application of computer science to systems controls, robotics, and artificial intelligence;
- electrical applications and the development of electrotechnologies;
- demand-side management (although currently North American utilities are interested in conservation, whereas Europeans are trying to increase off-peak demand);
- nuclear energy, despite sociopolitical restrictions that are presently slowing nuclear development; and
- minimizing environmental impacts.[58]

In addition, countries put a high priority on technologies they consider of key strategic value:

- photovoltaic energy in Japan;
- nuclear fusion and environmentally friendly coal combustion in the United States; and
- alternative energy in Sweden.

In Canada, national research on the peaceful uses of nuclear energy has had the most important direct identifiable impact on the manufacturing sector of any R&D program.[59] Indeed, Ontario Hydro's highest research priority remains nuclear energy: about 30 per cent of its internal research budget in 1989, or $22 million, as well as a $45 million contribution to the CANDU Owner's Group (COG) in 1989, went to it.

## R&D Intensity

In determining R&D intensity, R&D expenditures are normally discussed in terms of percentage of revenues. In a sector subject to international competition, this is valid because revenues can be compared. But electricity prices in a monopoly situation are not established by the market, and therefore revenues are not strictly comparable between electrical utilities. In addition, electrical utilities have different cost structures depending on the energy source (hydroelectric, thermal, nuclear, etc.). Therefore, comparisons that use electric-utility revenues can only be considered with caution.

To compensate for this problem, it is useful to consider the ratio of R&D expenditures to the quantity of energy sold as well as to revenues (Table 2). The energy sold appears to be a common denominator, somewhat eliminating the distortions in the revenue figures caused by price manipulation and the variability in cost structures among utilities.

Based on these two measures of intensity, it appears that by international standards Canadian utilities are in the middle of the pack as R&D performers.[60] Compared with most other sectors reviewed in the Sectoral Technology Strategy Series, this is a good performance. But note how by either measure it is the Japanese who make the biggest effort. The Japanese model merits consideration. Japanese utilities are required to pay a tax of 1¢/kWh of their electricity sales. This tax supports a fund used exclusively for national R&D projects. The utilities draw on this fund in accordance with the national R&D mandates they are assigned.[61] Partly as a result of this forced R&D investment, the R&D intensity of the Japanese electric-power sector is about two or three times that of other major industrial countries.[62] Significantly, this parallels many other sectors in which Japanese firms do more R&D than their counterparts elsewhere. (See Science Council of Canada Sectoral Technology Strategy Series, No. 3: *The Canadian Iron and Steel Sector*; No. 4: *The Canadian Automotive-Vehicle Sector*; No. 6: *The Canadian Petrochemicals and Resins Sector*; No. 8: *The Canadian Nonferrous-Metals Sector*; No. 10: *The Canadian Machinery Sector*; and No. 14: *The Canadian Electronics Sector*.)

In absolute terms, public electric utilities are major R&D players in Canada.[63] Ontario Hydro and Hydro-Québec are fifth and sixth, respectively, on the list of the top 20 Canadian R&D spenders (immediately behind BCE Inc., Pratt & Whitney, IBM Canada, and AECL). If Ontario Hydro and Hydro-Québec were combined, they would rank second.

## Procurement by Public Electric Utilities

Public utilities are important buyers of products and services needed for the construction and maintenance of their generating, transmission, and distribution networks. For example, Ontario Hydro, the most important user of CANDU in the world, can assure the success or failure of the reactor. Its important research programs in this area, coupled with those of the federal government, Hydro-Québec, and New Brunswick Power, support ongoing improvements to CANDU.

Table 2. Public electric utilities (1989) (millions $)

| | Canada | | | United States | Europe | | | | | Japan | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | HQ | OH | BCH | BPA | Germany | Belgium | France | Italy | Sweden | Tokyo | Kansai |
| Sales (TWh)* | 137.5 | 134.5 | 42.7 | 77.5 | 126.3 | 57.2 | 340.7 | 182.4 | 77.3 | 204.5 | 112.3 |
| Sales revenues | 5 503.0 | 6 255.0 | 1 769.0 | 2 444.0 | 10 964.6 | 5 077.5 | 26 916.5 | 13 571.1 | 3 085.5 | 35 172.7 | 17 375.5 |
| Capital (fixed assets) | 30 810.0 | 32 362.0 | 8 245.0 | 7 956.6 | 6 601.9 | 848.2 | 78 050.5 | 62 817.4 | 10 748.8 | 77 824.1 | 42 126.4 |
| R&D expenditures | 112.0 | 128.7 | 10.0 | 20.4 | 111.6 | 39.2 | 603.5 | 179.6 | 51.8 | 1 300.3 | 669.6 |
| R&D as a ratio of energy sales ($R&D/TWh) | 0.815 | 0.957 | 0.234 | 0.263 | 0.884 | 0.685 | 1.771 | 0.985 | 0.670 | 6.358 | 5.963 |
| R&D as a percentage of sales revenues | 2.0% | 2.1% | 0.6% | 0.8% | 1.0% | 0.8% | 2.2% | 1.3% | 1.7% | 3.7% | 3.9% |

Source: MARCON Management Consultants Ltd., "Rôle, stratégie et politiques des entreprises de service public électrique en matière de R&D," contract report prepared for the Science Council of Canada, 1991 (unpublished), 6.

* TWh = terawatt-hours; 1 tera- = $10^{12}$
HQ: Hydro-Québec
OH: Ontario Hydro
BCH: B.C. Hydro
BPA: Bonneville Power Administration
Germany: RWE
Belgium: Laborolec
France: Électricité de France (EDF)
Italy: Enel
Sweden: Vattentall
Tokyo: Tokyo Electric Power Company (TEPCO)
Kansai: Kansai Electric Power Company

Similarly, Hydro-Québec, through procurement policies that favour local contractors, has helped form several consulting-engineering firms of international renown. For instance, three important consulting-engineering firms in Quebec are Lavalin, with 4300 employees (now merged with SNC); SNC, with 2055 employees; and Dessau, with 608 employees.[64] Each of these has benefited from Hydro-Québec's contracting-out policy.

The producers and distributors of electricity can greatly affect the manufacturing sector through their purchasing policies. Ontario Hydro, Hydro-Québec, and B.C. Hydro have acquired, over the years, technological know-how in particular areas. This allows them to evaluate technologies, develop some of these, and influence their suppliers, which, in certain circumstances, can stimulate the development of innovative new products.[65]

## The Impact of Electric-Utility R&D

R&D conducted by public electric utilities improves their performance as producers, transmitters, and distributors. Their R&D is not specifically intended to promote manufacturing activity in the electrical sector. Nevertheless, in certain favourable circumstances, utility R&D has a direct impact on the electrical manufacturing sector.[66]

Among the utility's immediate goals are reducing costs, improving network reliability, displacing competing energy types, demand-side management, protection of the environment, and rational use of energy. If their accomplishment helps or requires the development of products that can be manufactured by Canadian companies and eventually exported, then the R&D can have a beneficial impact on the manufacturing industry.[67]

In the past few years, some Canadian public utilities, notably Hydro-Québec and Ontario Hydro, have undertaken R&D on electrotechnologies. The goal is to improve the efficiency of industrial processes and the competitiveness of their industrial clients.[68]

Hydro-Québec's R&D in this area is undertaken primarily by its IREQ research centre and its Laboratoire sur les technologies électrochimiques et les électrotechnologies (LTEE). With the goal of developing electrotechnologies that are more efficient than current processes based on competitive sources, research is directed toward the following objectives:[69]

- developing and adapting high-temperature processes in metallurgy and chemistry;
- developing and adapting industrial drying processes;
- developing low-temperature processes, principally in fluid heating; and
- developing, in concert with industrial partners, new technologies in industrial chemistry.

LTEE also develops and demonstrates the feasibility of electrotechnologies and electrochemical processes. The laboratory collaborates directly with several university research centres. Its annual budget is about $12 million. One-third comes from industrial clients, one-third from a federal-provincial agreement, and one-third from Hydro-Québec.[70]

Ontario Hydro's research department is concerned with several electrotechnologies, including electric arc, microwaves, lasers, and heat pumps.[71]

Some Canadian electric utilities make notable efforts to commercialize their technologies through, for instance, the New Business Ventures of Ontario Hydro or Nouveler, the subsidiary of Hydro-Québec. New Business Ventures grosses more than $50 million annually from marketing Ontario Hydro technologies. However, the R&D activities of utilities have had a modest impact on Canadian manufacturing competitiveness.[72]

Hydro-Québec's research program gives rise periodically to spin-off companies charged with selling technology internationally. The utility recently announced the incorporation of one of its new affiliates, System M3i Inc., which is licensed to sell a new software program. The software runs on a microcomputer and is used to manage an electricity or other distribution network. The first buyer was the Department of Water & Power of Los Angeles. Another example of the impact of Hydro-Québec's research is the development of improved turbines and network simulators.[73]

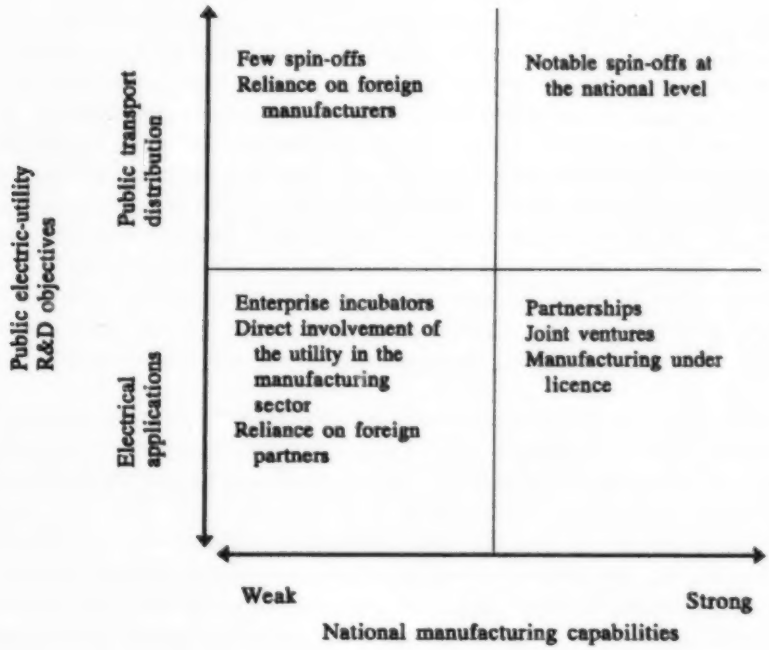
Utility R&D in electrotechnologies represents a different situation. In this area of R&D, the goal is to introduce users to systems and products that will influence electricity demand in the direction desired by the utility. The utility R&D is not limited to occasional spin-offs, but rather it involves a close and sustained collaboration with the manufacturing industry. Utility R&D in this area is beginning to have a major impact in Canada and warrants high priority. Electrotechnologies also present excellent export opportunities.[74]

Some Canadian utilities have recognized the problem Canadian industry faces in developing electrotechnologies, and they have supported the operations of the Canadian Committee on Electro-

technologies (CCE), a non-profit, tripartite group with representatives from utilities, industry, universities, and the federal and provincial governments. Hydro-Québec has played a lead role in its activities. CCE is dedicated to technology diffusion, education, and information support across Canada. It publishes a regular bulletin, *Electroflash*, offers dedicated university short seminars and courses on electrotechnology engineering (typically more than 50 each year), maintains a large library, disseminates results of global electrotechnology research to its members, and holds regular conferences and industrial meetings.

The impact and benefits of utility research depend on how prepared Canadian firms are to exploit opportunities offered by such research. This research will improve the competitiveness of manufacturing firms only to the extent that the firms have the capacity and the commercial potential to benefit from it. Figure 2 illustrates this situation.

Figure 2. Impacts of public electric-utility R&D




Source: MARCON Management Consultants Ltd., "Rôle, stratégie et politiques des entreprises de service public électrique en matière de R&D," contract report prepared for the Science Council of Canada, 1991 (unpublished), 61.

## National Industrial Infrastructure

The Canadian electrical-manufacturing sector made just under $9 billion in shipments in 1988, compared with a total of about $300 billion for all Canadian manufacturers. Imports of electrical

products in 1988 were much higher than exports: $4.8 and $1.4 billion, respectively.[75] This poor trade performance is typical of the Canadian machinery sector as a whole. (See Science Council of Canada Sectoral Technology Strategy Series, No. 10: *The Canadian Machinery Sector*.) Most Canadian electrical manufacturers are affiliates of foreign multinationals. Usually, multinationals concentrate their R&D in their home countries and their client services near their markets. As a result, little R&D is done in Canada.[76] But having very few Canadian multinationals leads to a lack of R&D on the part of manufacturers.

R&D expenditures of Canadian electrical manufacturers are about $136 million annually. This represents about 2.5 per cent of sales and is relatively low by international standards in this sector.[77] The affiliates of foreign multinationals take products designed by the parent company and adapt them to the local market. In certain cases, the affiliates develop a narrow range of products for the international market under a company-assigned world-product mandate.[78]

It is difficult to establish a causal link between the level of R&D of public electrical utilities and national industrial competitiveness. R&D effort has a multiplier effect to the extent that the manufacturing sector itself has the capacity to contribute to joint R&D projects (as in France and Sweden), undertake R&D on behalf of public electric utilities (as in the United States), or assist utilities in developing prototypes and commercial products (as in Japan).[79]

Only occasionally are Canadian utilities able to find Canadian partners capable of collaborating in their research efforts or even benefiting from industrial spin-offs of their research. R&D by Canadian utilities that leads to a technological innovation might largely contribute to the competitiveness of foreign firms if they are the only adequate industrial available partners. In these conditions, there is little motivation for Canadian utilities to increase their involvement in R&D in sectors with potential industrial spin-offs.[80]

The most notable exception is the long-term collaboration between utilities using the CANDU nuclear system, AECL, and attendant private industrial firms. In this case, the manufacturer was the leader in a long-term development project that resulted in a product marketed around the world. Moreover, the CANDU system (which is technically different from U.S. or British nuclear systems) has shown an overall excellent record of availability (capacity factor) and appears to have an excellent safety record.

AECL was created in 1952 to develop nuclear technology for peaceful purposes. Its major accomplishment has been the development of the CANDU nuclear reactor. At the end of 1989, there were 339 large reactors in operation in the world, 20 of which were CANDUs. Today, the Canadian nuclear industry employs more than 27 000 people.

AECL, at the request of the Canadian government, established two commercial enterprises as part of the privatization program. Since October 1988 these enterprises, Nordion International Inc. and Theratronics International Limited, have respectively offered radiochemical services and medical products. AECL sold Nordion in 1991. AECL is also being restructured into two principal operations: AECL Research and CANDU Operations. AECL Research will be jointly financed by the Canadian government, Ontario Hydro, Hydro-Québec, and New Brunswick Power. It will continue to be responsible for national nuclear R&D programs. CANDU Operations will facilitate the participation of all the parties in the public and private sectors interested in CANDU.

AECL represents the single largest concentration of electric-industry R&D in Canada. AECL's skill, coupled with the practical expertise of Ontario Hydro, Hydro-Québec, and New Brunswick Power, helps Canadian manufacturers of CANDU parts sell their products to other countries.

Over the years, the Canadian government has invested more than $4 billion in R&D at AECL. Federal funding will total $176 million in 1991, which is 92 per cent of revenues of $191 million.[81] This support has gone to one of the very few elements of the Canadian electric-power machinery subsector that has technological capability in Canada.

R&D linked to a purchasing policy favourable to national manufacturers, as with CANDU, strengthens firms by furnishing them with a market base on which they can become internationally competitive. The effectiveness of this type of policy, which is also employed in France, Belgium, and Italy, depends not only on the R&D effort but also on the dynamism and strength of the manufacturing sector.[82]

In Germany, the R&D-supplier link has been extended even further by both vertical and horizontal integration in a conglomerate involved in developing energy resources and in related activities such as engineering, construction, and manufacturing.[83]

In Japan, businesses are normally operated inside a family of related enterprises (*keiretsu*). Because of this, the manufacturing sector derives considerable benefits from public electric-utility R&D.[84] The utilities' R&D can readily be commercialized by an integrated manufacturing and service sector.

In Canada, utilities have a different relationship with suppliers. Hydro-Québec has a purchasing policy clearly favourable to Quebec suppliers. Ontario Hydro's practices are also favourable to Ontario companies, but less so than Quebec's are to its firms. In any case, the purchasing practices are not linked to R&D programs, even when the utility is directly involved in commercializing its research results. In one case, Hydro-Québec purchased a competing product instead of a product developed with its assistance.[85]

In summary, the differences in the intensity of public electric-utility R&D from one country to another do not explain the different impact that this R&D can have on the competitiveness of a country's manufacturing sector. A dynamic and robust group of national firms can profit from utility R&D and use it to enhance their international competitiveness. On the other hand, without such firms a country will find difficulty benefiting from public electric-utility research.[86]

# Opportunities and Growth Strategies for the Canadian Electric-Power Sector

With the size of their capitalization and their operating and R&D budgets, Canadian electric utilities have the ability to play a major role in a high-technology sector.[87] They can help develop and stimulate new technologies, both upstream in generation and transmission and downstream in utilization and electrotechnologies.

## Upstream Research on Generation and Transmission Technologies

Nuclear generation remains a positive and promising technology for Canada. The CANDU system has proven to be reliable and economical, certainly compared with competing enriched-uranium reactors typical of U.S. design (although recent problems with pressurized tubes inside Ontario Hydro's CANDU reactors have diminished their effective capacity factor in 1991 to only about average for all reactors). CANDU remains an excellent base-load generating technology, taking a 20-year view of its performance (it typically has an annual capacity factor of around 85 per cent). In the future, nuclear fusion may be an equally promising base-load technology. Canadian experiments, jointly sponsored by AECL and Hydro-Québec (IREQ), are under way. Energy, Mines and Resources Canada also provides support.

Canada's nuclear program provides important industrial benefits. By pursuing an independent nuclear-fission program of its own design, Canada has built an industrial infrastructure of suppliers for CANDU. For the rest of the sector, most of the supporting machinery and infrastructure are imported. In the more distant future, a distinctive Canadian program for fusion may offer similar benefits. Potential spin-offs could include lasers, advanced materials, and telecommunications equipment.

An area of industrial R&D that might have a bright future is in developing technologies that use coal to generate electricity. A market for such technologies could be Germany and the many countries of Eastern Europe that possess enormous reserves of coal but have no oil, gas, or hydroelectric potential. These countries have also placed a moratorium on nuclear energy. Another large potential market is the United States, where the coal segment of the electricity industry is considerable.[88]

A particularly exciting coal technology is fluidized-bed combustion. It offers up to 15 per cent gain in total efficiency, does not contribute at all to acid rain (as it has virtually no $SO_2$ emissions), and even avoids $NO_x$ formation and emissions of toxic minerals. Environmentally friendly coal combustion is one area in which Canada already has a substantial research effort financed by Energy, Mines and Resources Canada.[89]

A promising focus for utilities' R&D in Canada is on improving maintenance procedures to extend the lifetime of existing plants. To a considerable extent this is already being done. It is noteworthy that several Canadian plants, including reactors, could last beyond their life expectancies. Further opportunities may exist for positive payback from R&D that helps keep older equipment on line.

Finally, so-called high-temperature superconductors have received considerable publicity in the last three years. Such superconductors could mean that long-distance transmission losses could be reduced to zero. Given Canada's considerable remote hydro potential, superconductors represent an intriguing possibility. However, results so far are not conclusive enough to justify major new expenditures.

The oil shocks of the 1970s stimulated public- and private-sector interest in and support for alternative, renewable energy sources such as solar and wind. But very few of these technologies turned out to be economically or technically viable. Following the substantial drop in oil prices in the 1980s, interest in and support for alternative and renewable energy waned. Moreover, the severe Canadian climate and the substantial power needs of the Canadian economy militate against these technologies.

The United States has made more progress with renewable energy sources than any other major country. There, renewables now supply 23 per cent more energy than nuclear power. Eight states now get a fifth of their energy from renewables, and electric capacity from renewable energy sources other than hydropower grew tenfold in the 1980s to 9500 MW — equivalent to the output of 10 to 12 average-sized nuclear plants.[90] However, U.S. fiscal regulations are structured in a way that encourages development of renewable or alternative energy sources. This may be leading U.S. investments into less economical uses.

By some measures, renewable energy sources are environmentally preferable to fossil fuels or nuclear power. Solar, aeolian, and geothermal resources are plentiful and virtually inexhaustible. Most renewables produce little or no pollution directly (although there may be some indirect environmental problems, for example, in the manufacturing process) and few risks to public safety (although there can be some safety hazards to assembly workers or installers). And they are a domestic resource, avoiding the problems of fitful foreign energy supplies.[91] However, the debate about how economically competitive these renewable electricity sources will be in comparison with conventional fossil-fuel or nuclear generation remains unresolved.

Following are brief assessments of renewable or alternative electricity technologies not currently in use in Canada:

*Photovoltaics* — Photovoltaic cells convert sunlight directly into electricity. The light passes through a semiconductor, such as silicon, that is applied as a film to the surface of a dissimilar crystal, setting up a voltage and a current. This is the principle used in solar batteries. More than 40 companies worldwide manufactured photovoltaic cells that supplied approximately 35 MW in 1988. (Millions of watches and calculators are now a relatively minor but highly visible application of photovoltaics.) Japan is the leader in this technology. Japanese companies are now counting on large-scale commercialization about the year 2000. Price trends are strongly downward — from about $2.50/kWh in 1980 to perhaps $0.75/kWh in 1990. It may well be a competitive technology by 2000, given current Japanese electricity rates of about $0.25/kWh. This could be a very important technology in Canada's generating plants: photovoltaic cells could conceivably act as daylight peaking components. If they could be backed up with short-term storage (batteries), they could help meet peak demand in a deteriorating load-factor environment.

*Cogeneration* — Advances in small-scale power production are being led by cogeneration, which is the combined production of heat and power from one source. In the early 1980s, this was the fastest growing power-production method in the United States. Most cogeneration systems are installed in factories or large institutions such as hospitals; excess power is sold to utilities. Whether the fuel is natural gas, coal, municipal solid waste, or wood chips, cogeneration can, by increasing fuel efficiency, offer environmental benefits and cost savings. Cogeneration not only reduces acid rain and other forms of pollution by cutting total energy consumption, but also generates revenue from the sale of the electricity it produces. Ontario Hydro has been investigating cogeneration potential in Ontario.

*Geothermal energy* — Geothermal energy is obtained by capturing the heat produced in the interior of the earth. Volcanoes, geysers, and hot springs are the most common sources of such energy. In the

United States, base-load electric capacity from geothermal resources rose from 926 MW in 1980 to nearly 2700 MW in 1989. Geothermal energy now supplies 7 per cent of California's power. Unfortunately, geothermal resources are available in only a very limited number of locations, few of which are in Canada.

*Solar thermal power* — Solar thermal power plants use concentrators to focus sunlight onto a receiver, heating a liquid to produce steam or electricity. The heated fluid can be stored in insulated tanks for use at night and on cloudy days. Attention now is focused primarily on three systems: central receivers, parabolic troughs, and parabolic dishes. In general, solar thermal systems are not economical except in desert or tropical regions, and given Canada's climate, they are not likely to be a promising option for Canada.

*Solar building technology* — Passive measures include heat-retaining windows and buildings oriented to take maximum advantage of sunlight. Active measures include roof-top solar collectors in combination with pumps for hot-water heating. It may be possible to adapt this technology to Canada, but its application is likely to be limited.

*Wind* — Today, more than 16 000 spinning turbines provide 1 per cent of California's electric power, enough to serve 300 000 homes. California holds more than 80 per cent of the world's windmills; another 13 per cent spin in Denmark; Hawaii has 2 to 3 per cent; and the remaining 4 per cent are scattered around the globe. Some parts of Canada might be able to use this technology, but it relies on steady winds. There have been major technical problems with some Canadian experiments using wind for electricity generation.

*Hydrogen* — An electric current can separate water into hydrogen and oxygen by a process known as electrolysis. The hydrogen itself could then be used for fuel, either directly or as an upgrader in coal or wood gasification or liquefaction. Current energy prices would not support such a process, even if the electricity was given away virtually free, because in Canada natural gas is available as an alternative source of hydrogen. There are also mighty problems to be solved in safety and storage of hydrogen. But hydrogen used directly as fuel would have one great future benefit: it would not produce $CO_2$ and hence would not add to global warming. Although not a commercial prospect for many years, electrolytic hydrogen is a possibility in the very long term. Interestingly, and most significant, in theory the electric power needed for hydrogen production could be off peak, that is, the electrolysis plant would be a load the utility could service as it wished. Although not free, this implies a low cost for the power used in hydrogen production.

In sum, although there are possibilities for upstream research on generation and transmission, the potential for new technologies is limited in Canada, or Canadian utilities and related agencies are already doing such research.

## Downstream Research: Utilization and Applications

Research on electricity utilization and applications is relatively new. Already, however, several possibilities have emerged. These include:

*Demand-side management technologies* — These technologies affect the load factor of electricity demand by either reducing loads or shifting demand to more convenient (off-peak) times. Examples

are remote control of hot-water heaters, fluorescent lighting, and more efficient appliances and machinery.

*Electrotechnologies* — These technologies use electricity in entirely new applications or as new substitutes for other fuels. Electrotechnologies encompass four broad areas: electrolytic technologies such as electrochemical synthesis and reduction; high-temperature electroheat technologies such as electric-arc melting; low-temperature electroheat technologies such as industrial heat pumps; and motive technologies, including high-efficiency motors and variable-speed drives.[92]

*Electric vehicles* — Electric cars remain intriguing possibilities for several reasons. They offer decreased reliance on potentially unstable petroleum supplies. They could, in principle, be recharged at night (off peak). Their cost per kilometre might be low because they have relatively few moving parts. They offer environmental benefits, particularly in urban areas with dense traffic. The problem, of course, is battery technology. At present, no battery system offers adequate driving range and durability. Canada's cold climate exacerbates the difficulty. Nevertheless, the prospect remains very positive for the long run. Japanese utilities, like TEPCO, are already cooperating with Japanese automakers to develop an electric car.

If Canadian electric utilities offered differentiated rate structures based on load-factor characteristics, entirely new markets would be created elsewhere in North America for both new supply and new demand technologies. A peak-demand rate could encourage new supply options that are currently too expensive in an all-averaging rate structure; an off-peak rate would encourage new markets for electric products currently fuelled by cheaper alternatives.

Opportunities exist to balance the load on the electric grid both daily and seasonally. These are the most important R&D opportunities available to electric utilities. But they must also put in place the price signals, that is, an off-peak rate, to 'fill the valley.'

## Hybrid Heating[93]

One option to fill the valley is dual-energy or hybrid heating systems. Although hybrid heating is not the only demand-side balancing option, it has been used by several utilities in the United States, notably the Minnkota Power Co-operative in Minnesota and North Dakota, and to a certain extent by Hydro-Québec. Accordingly, considerable experience has already been obtained. It is commercially viable at the present time and would offer substantial industrial benefits to local regions of Canada. In an off-peak (differentiated) rate structure, it could cut the costs of space heating by about 50 per cent or more in Canada. Instead of consuming so much oil, Canada would be able to export more. It seems fair to say that it remains particularly well suited to the Canadian environment of very severe winters but with large-scale base-load generating potential. It is an intriguing option available to the Canadian electric-power sector.

As its name suggests, a hybrid, or dual-energy, system uses two different energy sources to provide space heating for any given building. One of these is electricity. The other is a storable fuel, such as oil, propane, natural gas, or wood. The critical factor is that electricity is not required to carry the entire space-heating load.

Approximately 30 per cent of all Canadian buildings already have oil furnaces. Converting them to hybrid heating systems can be achieved by simply installing an electric heater in the furnace's plenum. Furthermore, with the exception of the coldest periods in Canadian winters, only a moderate amount of power is required to keep most buildings warm — the type of power that the existing

electric grid can easily provide. In a hybrid system, the back-up oil furnace can be made to operate only at times when there is peak demand on the electric grid. Tests by Ontario Hydro, AECL, and Hydro-Québec and the implementation of hybrid heating by the Minnkota Power Co-operative in the northern United States have shown that this system notably improves the load factor on the electric grid, with a corresponding improvement in the capacity factor of electric-power generating plants.

With dual-energy or hybrid systems, space heating avoids being a disastrous synchronized load. Instead, it becomes the perfect load that utilities would most like to have: one that they can essentially control. It is a very large load; it can absorb huge power output. But the load is totally or overwhelmingly off peak — it is a 'valley filler.' Yet, at least 80 per cent of any building's heat load can still be met with electricity.

There are two main methods for controlling hybrid or dual-energy systems. In Hybrid I, electricity provides space heat except when the outside temperature drops below a preset value. Then the storable heat source, such as oil, is used instead of electricity. Control over switching between electric and oil heating is retained within the building itself.

The Hybrid II method is even better. Capacity is allocated to heating only when it is not needed for other purposes, that is, when it is off peak. When total electricity demand approaches capacity, the utility switches off a sufficient number of heaters by remote control — there are several technical methods of accomplishing this — so as to provide enough electricity to satisfy the increasing demand. The heaters can then be reconnected remotely as the general demand declines. This is the system used by the Minnkota Power Co-operative. With this technique, an electric utility does not even have to carry reserve generating power; it can commit all power to space heating so long as, in case of generator breakdown, the remotely controlled hybrid-system electric heaters can be disconnected to reduce load on the remaining operating plant.

It might well be possible to adapt dual-energy concepts to industrial-sector needs. For example, in some applications an electric furnace could be temporarily replaced during peak electric demand by a coal- or gas-fired furnace. A more distant possibility could be the industrial heat pump, supplemented by, for example, coal combustion for industrial-process heat.

About 80 per cent of Canada's total space heat currently provided by oil could theoretically be provided electrically if all oil-heated Canadian buildings (residential, commercial, and industrial) were connected in a hybrid network.[94] Canada's total oil consumption could be reduced by the equivalent of about 250 000 barrels of crude oil per day. Such a reduction would allow Canada to achieve and retain oil-exporter status.

The use of electric-oil hybrid systems for space heating would provide new industrial opportunities for Canadian manufacturers of electrical products. At least five designs from domestic manufacturers for residential hybrid heating equipment have been accepted by the Canadian Standards Association. The estimated market value of electrical equipment for hybrid systems would be about $3.0 billion (1991 dollars). These billions of dollars' worth of markets represent new industrial opportunities for Canadian manufacturers, paid for by corresponding reductions in fossil-fuel consumption. In turn, either fossil fuels do not have to be imported, or domestic supplies could be exported.

The adoption of electric-oil hybrid heating would result in many advantages for electric utilities.[95] The adoption of hybrid systems in oil-heated homes would increase the demand placed on the utility's generating plant in off-peak times throughout the heating season and would raise the annual load factor to 85 per cent from its present 65 per cent. It would also raise the capacity factor to 75 per cent from the present typical 50 per cent. Most of the load would thus be base, with a small amount of intermediate and no peaking.

Base-load electricity could be generated and distributed at off-peak times at a marginal cost to the utilities of about 2.3¢/kWh or less, which is much lower than the current average rate. Under

future ideal conditions, a utility with optimal plant could charge as little as 0.5¢/kWh for off-peak power in a hybrid system. These figures are, of course, theoretical, and the full use of off-peak capacity would take several years to achieve. The potential is very large, however, and most of it could be realized. Finally, hybrid heating systems would still allow summer down time for utilities to carry out necessary scheduled annual maintenance.

However, without differentiated rate structures (that is, off-peak rates) the consumer has little or no incentive to purchase a hybrid heating system. But if the savings resulting from the increased efficiency of hybrid heating were to be passed on to consumers in the form of differentiated rate structures, which reward users for the purchase of off-peak electricity and penalize them for the purchase of peak-load electricity, electric utilities could make hybrid heating less expensive than alternatives. Such rate structures could also be applied to commercial and industrial users; these users could use hybrid or dual-energy principles for industrial processes, as well as for space heating.

Hydro-Québec has already developed a differentiated rate structure for hybrid systems. The utility originally gave consumers installation grants that, with the federal government's former Canadian Oil Substitution Program financing, made the purchase of hybrid or dual-energy systems essentially free to consumers. This has been quite successful: there are now thousands of hybrid systems in Quebec.

Several other utilities in Canada, notably Ontario Hydro, offered dual-energy or hybrid heating programs in the early 1980s. The Ontario Hydro program was not really successful. This seems to be largely the result of the weak incentive program the utility offered in marketing the system. No preferred rate was granted. Instead, a modest grant of $200 (1982 dollars) was available to consumers to offset installation costs. Ontario Hydro, however, also tried to enforce standardized designs for hybrid systems to reduce their final cost to consumers. Since this limited both choice to consumers and profits to manufacturers and contractors, this effort was resented. Many contractors felt they were being asked to help the utility's load factor (and hence costs) at their own expense. An off-peak rate, as offered by the Minnkota Power Co-operative, would likely have been a great deal more successful.

Dual-energy or hybrid heating systems would go a long way toward bringing about free-market competition. Household, commercial, and industrial users could also switch at their pleasure between the two energy sources. However, it should be appreciated that off-peak electric power from base-load generators would likely always be cheap.

In summary, based on the best available cost data from experimental results and actual experience, electric-oil hybrid heating systems offer the greatest efficiency and financial benefits of the space-heating alternatives, and they allow the maximum realization of economies of scale in electricity generation. They present many advantages, but only if utilities pass off-peak cost savings back to consumers.

## Growth Strategies

The R&D programs of Canadian utilities address many leading-edge technologies such as fusion, the new generation of fission, superconductivity, and telerobotics.[96] The CANDU nuclear system and Canadian expertise in developing hydro resources demonstrate that Canada's electric-power R&D is first rate, so far as it goes. But R&D expenditures are small by international comparison.

Perhaps the best opportunities for strengthening Canadian R&D are in applications and utilization of electricity, notably the development of electrotechnologies.[97]

The diversification of utilities into high-technology manufacturing is not without precedent.[98] In Japan, a utility such as the Tokyo Electric Power Co. is part of a conglomerate involved in a number of activities that are complementary or connected to its principal business of electric-power

generation and distribution.[99] In Germany, the electric utility RWE has formed a conglomerate that is integrated both vertically and horizontally. The conglomerate is involved in energy resources and in connected activities such as gas and water distribution, construction, and the manufacture of electrical equipment.[100] Another example is the involvement of the Norwegian power company, Norsk-Hydro, in the metals sector.[101]

The spin-offs from electric-utility R&D for the manufacturing sector can be substantial.[102] For example, with an annual investment of $10 million in R&D in commercial electrotechnologies, Électricité de France estimates that its industrial partners would eventually generate $100 million worth of business annually.[103]

Nearer home, Bell Canada Enterprises demonstrates the dynamic effect that a business that generates significant permanent revenues can have on the economy.[104] Public utilities that provide electricity and telephone services accumulate large profits that they can invest in high-growth industrial sectors of the future.[105]

However, the amount of R&D undertaken by Canadian utilities remains small in a worldwide context and the utilities have very little room to manoeuvre in participating in medium- or long-term strategic technology development.[106] Moreover, in Canada the commercialization of public electric-utility research is episodic, and its industrial spin-offs are generally few.[107]

Indeed, the funding of advanced and basic research and strategic technology development by Canadian utilities ($15 million by Hydro-Québec and $18 million by Ontario Hydro) is very small when one considers that:[108]

- Japan's R&D, Demonstration and Evaluation (RDDE) program on the use of photovoltaic energy is funded to the tune of several hundreds of millions of dollars; and,
- in the United States, about $500 million is dedicated each year to nuclear-fusion research by governments and research institutes.[109]

Given Canada's small R&D funding, there is serious question about the position it can hope to achieve in the key technologies of the electricity sector in the 21st century.[110] Despite the strong case for additional R&D, the large government debt and the need for budgetary restraint make it unrealistic to propose massive injections from existing government funds to accelerate R&D. However, other means of financing may be available. Canadian utilities could:[111]

- cooperate more closely with industry (for example, joint ventures) and, if this is not successful, become directly involved in the industry through acquisition or alliances;
- develop manufacturing linkages according to the German model, in which the utility is integrated into the entire electrical-equipment manufacturing sector; Bell Canada Enterprises, with its linkages to Northern Telecom and Bell-Northern Research, provides a similar model from another sector in Canada;
- coordinate their purchasing power to strengthen common R&D activities and avoid the fragmentation of an already small market in Canada;[112]
- strengthen cooperation among utilities in Canada and abroad and benefit from the synergism that joint projects foster; and, above all,
- create new markets for entirely new products; one strategy for stimulating such markets is to offer differentiated rate structures.

# Conclusion

Canada lies in the middle of the pack among countries in the performance of R&D by the electric-power sector. Among Canadian sectors, though, the hydro companies are important performers of R&D. Unfortunately, Canadians do not draw all the benefits they could from the substantial R&D investment made on their behalf by public electric utilities. Utilities themselves seem to recognize this and would like to enhance the benefits. To remedy this situation and increase the role the utilities play in strengthening Canada's international competitiveness, some experts advocate more government intervention or cooperation in this sector; others advocate privatization.

However, several factors make either strategy questionable. First, R&D in the Canadian electric-power sector is small in absolute terms by international standards, and the sector's investment in cutting-edge high technologies is particularly weak. More important, there are currently very few benefits or spin-offs for Canadian manufacturing from this R&D owing to the absence of a strong related Canadian industrial structure. On the other hand, Canadians benefit from having almost the lowest electricity prices in the world.

The Canadian electric-power sector has an opportunity to develop off-peak power technologies. If utilities provided price signals to consumers that made clear how the costs of power varied over time and encouraged consumers to switch, then substantial opportunity for developing new electrical equipment would exist. Canada could take the lead in this. A striking example is dual-energy or hybrid heating systems. This technology appears to justify large-scale generation and the current generating philosophy of utilities. But the utilities must differentiate rate structures and offer off-peak rates.

# Appendix: Framework for Technology Strategies

As part of the methodology for analysing each sector, the Science Council of Canada sought whenever possible to assess company technology strategies according to the following framework:

| | adopt and adapt | innovation | breakthrough |
|---|---|---|---|
| product | | | |
| process | | | |

## Strategy Classes

Adopt and adapt: Acquire a technology and adapt it to serve as a competitive platform.

Innovation: Incrementally improve on winning technology to get greater market share or maintain competitive edge.

Breakthrough: Seek to create a discontinuity in the marketplace, thereby leaping ahead of the competition.

The company case studies generally looked for at least seven key dynamics influencing a company's technology strategy:

- three internal dynamics:
  - competitive position,
  - capacity for innovation, and
  - strategy and vision; and
- four external dynamics:
  - customer demands,
  - competitive rivalry,
  - supply condition, and
  - available technology.

The methodology also incorporated essentially a three-step process for each sector. In the first step one or more contractors analysed the main elements in the competitive and R&D performance of the Canadian sector and its leading foreign competitors. The second step included evaluation of the contract report(s), discussion with contractors and other experts, additional in-house research, and preparation of a draft Council report. In the third step, external reviewers commented on one or more drafts of the Council report, which were then revised and refined as required, drawing on the advice of the liaison person for that sector on the Steering Committee (see Acknowledgements). For some sectors, the third step also involved several external reviewers in a small workshop, one part of which

helped define some elements of a potential action plan for the sector. The report was then submitted for final approval to the Executive Committee of the Science Council, before being forwarded to Industry, Science and Technology Canada.

# Notes

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10. Energy Probe, op. cit., 7.

11. Ruff, op. cit., 15.

12. Ibid., 18.

13. Robert L. Frost, "Public and private technologies in capital-intensive industry: The cases of electrical power in France and New York," paper given at International Interdisciplinary Workshop on Science-Technology-Politics, University of Maria Curie, Lublin (Sklodowska), Poland, 27-29 September 1991.

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19. "Encounter: Jean-Thomas Bernard," *Financial Times of Canada* (27 May 1991): 35.

20. MARCON, op. cit., 62.

21. Ibid., 61.

22. Corcoran, op. cit.

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34. Ibid.

35. Ibid.

36. Ibid.

37. Ibid.

38. Ibid.

39. Ibid.

40. Ibid.

41. Passmore, op. cit., 6.

42. Ibid., 7.

43. Ibid.

44. Ibid.

45. Ibid.

46. Ibid., 2.

47. Ibid., 14.

48. Ibid., 18.

49. Ibid.

50. Source: Ontario Hydro and Hydro-Québec.

51. In the course of their research for the Ministry of State for Science and Technology (MOSST) project, Ontario Hydro used a real interest rate of 4.5 per cent; Hydro-Québec, 6 per cent. However, this real interest rate does not capture all the elements included here.

52. Load factor = (average load ÷ peak load) × 100%. It is an index of load. By contrast, capacity factor is an index of capacity utilization.
Capacity factor = (actual output ÷ theoretical output) × 100%.

Load factor is always higher in practice than capacity factor. This is essentially because utilities have reserve equipment that operates only in case of breakdowns or unscheduled outages. Of course, if all goes well, it will stand idle. Although this reserve component has no bearing on demand load characteristics, it does get included in the capacity-utilization calculations. Since it is designed to stand idle — and usually does — it produces very little output, and this statistically drags down the capacity factor. Moreover, a utility may have surplus capacity above reserve (most in Canada do). This further depresses the capacity factor relative to the load factor.

53. Although a utility has to dedicate 10 kW per building for peak space heating, the capacity of the electric space-heating equipment in the same building would have to be much greater — 20 kW or 25 kW. This ensures that there is always enough capacity to keep the house warm under different circumstances.

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93. Rick Clayton, *Electric/Oil Hybrid Heating Systems* (Ottawa: MOSST 1984). See Ch. 3, "Potential of the electric hybrid system."

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